Office of the Ohio Consumers' Counsel

Your Residential Utility Advocate

Janine L. Migden-Ostrander
Consumers' Counsel

/

RECEIVED
FEB 15 2005
OFFICE OF THE SECRETARY

February 14, 2005

Secretary
Securities & Exchange Commission
450 Fifth St. NW
Washington, DC 20549

RECEIVED
FEB 16 2005
Office of Public Utility Regulation

Re: File No. 070-10254
Cincinnati Gas & Electric

Dear Secretary:

Enclosed please find an original and four copies of the Office of the Ohio Consumers' Counsel's Motion to Intervene and Protest and in the Alternative Motion for Hearing with Attachments in the above case number. Please send back one date stamped copy in the self-addressed envelope.

If you have any questions, please contact me directly at (614) 466-1311.

Thank you.

Denise Willis

Denise Willis
Case Team Assistant

Enclosures

RECEIVED
FEB 15 2005
OFFICE OF THE SECRETARY

UNITED STATES OF AMERICA

**BEFORE THE
SECURITIES AND EXCHANGE COMMISSION**

In the Matter of the Cinergy Corp. Application of)
Declaration Under the Public Utility Holding Company Act)

File No. 070-10254

MOTION TO INTERVENE AND PROTEST, AND IN THE ALTERNATIVE, MOTION FOR HEARING OF THE OHIO CONSUMERS' COUNSEL

George Dwight II
Cinergy Corp.
139 East Fourth Street, 25 AT2
Cincinnati, Ohio 45202
513-287-2643 (P)
513-287-3810 (F)
gdwight@cincergy.com

William C. Weeden
Skadden Arps Slate Meagher & Flom
1400 New York Avenue, N.W.
Washington, D.C. 20005
202-371-7877 (P)
202-371-7012 (F)
wweeden@skadden.com

Counsel for Cinergy Corp.

Jeffrey L. Small
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215
614-466-1292 (P)
614-466-9475 (F)
small@occ.state.oh.us

Counsel for the Office of the
Ohio Consumers' Counsel

UNITED STATES OF AMERICA

BEFORE THE
SECURITIES AND EXCHANGE COMMISSION

In the Matter of the Cinergy Corp. Application of Declaration Under the Public Utility Holding Company Act	))	File No. 070-10254

MOTION TO INTERVENE AND PROTEST,
AND IN THE ALTERNATIVE,
MOTION FOR HEARING
BY
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

Pursuant to Rule 210(b) ("parties") as well as Rules 154 ("motions") and 150-153 of the Rules of Practice of the Securities and Exchange Commission ("Commission") and the Commission's Notice dated January 21, 2005, the Office of the Ohio Consumers' Counsel ("OCC") hereby moves for leave to intervene in the above-captioned docket. This docket involves the filing on September 30, 2004 ("Application") and the amended filing on January 19, 2005 ("Supplement") by Cinergy Corp., a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"). Cinergy Corp. ("Cinergy") is the parent company of the Cincinnati Gas & Electric Company ("CG&E") and The Union Light, Heat & Power Company ("ULH&P;" collectively with CG&E and Cinergy Corp., the "Company" or "Applicant").[1]

The name, address, telephone, facsimile and e-mail address of the OCC's designated representative for receipt of service in this proceeding, qualified to practice by

---

[1] Supplement, Item 1.A.

the Ohio Supreme Court, is:

Jeffrey L. Small, Esq.
Assistant Consumers' Counsel
Ohio Consumers' Counsel
10 West Broad Street, 18th Floor
Columbus, Ohio 43215
Phone: (614) 466-8574
Fax: (614) 466-9475
E-mail: small@occ.state.oh.us

TABLE OF CONTENTS

I. INTRODUCTION

On September 30, 2004, the Company filed a request that was later supplemented on January 19, 2005.[2] The Company requested that the Commission allow CG&E to sell, pursuant to Section 12(d) of PUHCA and Commission Rule 44, its ownership interests in three electric generating facilities to ULH&P at net book value.[3] The Company's Application under PUHCA states that the sale "meets the goal of the Kentucky Public Service Commission ... that ULH&P acquire physical generating assets to serve its retail electric customers."[4] The Application and Supplement are nearly devoid of any mention of the effects of the sale on customers served by CG&E in Ohio.

The OCC represents residential utility consumers. CG&E serves approximately 600,000 residential customers in Ohio. None of those consumers should pay higher rates as the result of the sale of generating assets from CG&E to ULH&P.

II. MOTION TO INTERVENE

The OCC is the State of Ohio's residential utility consumer advocate, empowered under Chapter 4911, Ohio Rev. Code Ann. (Anderson 2000), to represent the interests of Ohio's residential utility consumers in proceedings before state and federal administrative agencies and courts. The OCC has actively participated in numerous regulatory proceedings at the state and federal level.

---

[2] Form U-1 Declaration ("Application"); Form U-1/A ("Supplement").

[3] Application, Item 1.A. ("at net book value"); also Supplement, Item 1.C.

[4] Application, Item 1.A.

The OCC represents the interests of Ohio's residential electricity consumers who are retail customers of CG&E. These residential customers have paid for generation service provided by CG&E's portfolio of generating assets, including the three plants whose sale is the subject of the above-captioned case.[5] CG&E proposes to sell the depreciated generating assets to satisfy the Kentucky Public Service Commission ("KPSC" or the "Kentucky Commission"), thereby shifting costs to the disadvantage of CG&E's customers in Ohio.

Pursuant to a recent decision by the Public Utilities Commission of Ohio ("PUCO" or the "Ohio Commission"), CG&E will charge customers for generation service according to a tracker ("SRT") placed into effect to recover CG&E's costs of acquiring generation resources.[6] CG&E must acquire additional generation resources because it is short of those needed to serve its Ohio customers.[7] CG&E's acquisition of those resources -- including its planned purchase or construction of one or more generating plants -- is expected by the OCC to be at costs above the average cost associated with running the plants that the Company intends to sell to ULH&P.

The OCC has opposed CG&E's plans to provide high cost generation services in Ohio, and it opposes the sale to ULH&P as part of the Company's plan to shift costs to

---

[5] Supplement, Item 1.D.

[6] *In re CG&E Post Market Development Period Service*, PUCO Case No. 03-93-EL-ATA *et al.*, Entry on Rehearing at 8, ¶12(c) (November 23, 2004) (attached). The Entry states that the SRT is intended to flow through costs associated with purchased power. However, CG&E has applied to the PUCO for approval "to recover certain costs [associated with the purchase or construction of generating facilities] and a reasonable return on the capital investment in such generating facilities and to recover such costs and return through its system reliability tracker [SRT] through 2008." *In re New CG&E Power Plant*, PUCO Case No. 04-1811-EL-AAM *et al.*, Application at 1, ¶3 (December 2, 2004) (attached).

[7] CG&E reports a "reserve margin for 2004 ... less than 5.2%, requiring it to rely on several hundred MWs of forward purchased power," and the utility "anticipates that forward reliability purchases will provide approximately 20% of its peak load" in 2005. *Id.* at 4, ¶5.

Ohio's residential and other customers. Thus, the Company's filing will affect the interests of the residential retail electricity consumers that the OCC represents.

No other party can adequately represent the interests of all of Ohio's residential consumers in this proceeding. The only entity having a connection with the State of Ohio in this proceeding is the Company itself, an entity that is not charged with protecting customers from unreasonable rates or utility practices that include a multi-state strategy that disfavors Ohioans.

The Commission noticed the CG&E Application on January 21, 2005, and established February 15, 2005 as the deadline for interventions and comments in this docket. Therefore, the OCC's intervention in this proceeding should be granted.

III. PROTEST

A. Introduction and Background

The Company's submissions in the above-captioned cases, including its Supplement, provide a bare bones description of the context in which it proposes to sell three generating plants from CG&E to ULH&P. The Application provides little detail on a range of topics that are needed for the proper evaluation of the Company's proposals. The Application's few references to Ohio law and regulations contain misstatements. The intent of the OCC's submissions in the above-captioned case is to provide a more complete context for the Company's proposed sale of generating facilities. Afforded with this complete context, the Commission can better render a fair decision regarding the proper value for the proposed sale involving the Company's affiliates. The proposal should be denied as presently structured.

B. Argument in Support of Denial or Hearing

1. Section 12(d) of PUHCA Sets the Standard for Judging the Sale.

PUHCA requires that the public interest in the above-captioned case be judged based upon the consideration provided by UHL&P and the effect on competitive conditions. Section 12(d) of PUHCA states:

> It shall be unlawful for any registered holding company ... to sell ... any utility assets, in contravention of such rules and regulations or orders regarding the *consideration to be received* for such sale [and] *maintenance of competitive conditions* ... as the Commission deems necessary or appropriate in the public interest or for the protection of investors or consumers....[8]

This section also demonstrates that protection of consumers is contemplated, and this must include consumers in Ohio.

Section 12(d) of PUHCA refers to "utility assets." Section 2(a)(18) of PUHCA defines this term:

> "Utility assets" means the facilities, in place, of any electric utility company or gas utility company for the production, transmission, transportation, or distribution of electric energy or natural or manufactured gas.

The three facilities that are the subject of the Company's proposed sale -- East Bend, Miami Fort 6, and Woodsdale generating plants[9] -- are all "facilities ... for the production ... of electric energy" as contemplated under PUHCA.[10]

Finally, the Commission has not set a rigid rule regarding what it "deems necessary and appropriate" under Section 12(d). For instance, a case that involved

---

[8] Emphasis added.

[9] Supplement, Item I.C.

[10] The Company appears to recognize the applicability of Section 12(d). Application, Item 2.A.; Supplement, Item 3.A.

settlement agreements with local oversight agencies resulted in the following with regard to the interpretation of Section 12(d):

> We do not object in principle to the pricing provisions of the Settlement Agreements. It is appropriate, however, to consider these transactions on a case-by-case basis, in consultation with other regulators, as contemplated by the policies and goals of the Settlement Agreements in reviewing a transaction for which our approval is sought.[11]

The Commission should consider not only the policies and goals of the KPSC, but also the interests of consumers in Ohio who are a great part of the "public" that is affected by the proposed sale.

2. A Sale at a Bargain Price Is Not in the Public Interest When the *Entire* Public Is Considered.

The Company's Application and Supplement are short on details regarding a range of regulatory matters that place the proposed sale in a new light. The Company states that Section 12(d) of PUHCA is "clearly satisfie[d]," emphasizing that the "KPSC found the Transfer in the best interests of ULH&P and its ratepayers" because "an RFP would not have benefited ULH&P's customers."[12] Entirely missing from the Company's analysis is the negative impact that the sale will have on CG&E's Ohio customers.

The Company proposes to change the ownership of generating facilities under circumstances where it must either make substantial purchases of power in wholesale markets or acquire additional generating facilities. During 2001, the Kentucky Commission required ULH&P to develop a "stand-alone integrated resource plan by June 30, 2004" that would include the study of the "acquisition of generating assets." The

[11] *Entergy Corp. et al.*, 1999 SEC Lexis 1232 at 22-23 (June 22, 1999); Release Nos. 35-27040, 70-8529.

[12] Application, Item 3.A.

ULH&P responded by offering to purchase, from affiliate CG&E, three generating facilities. ULH&P argued that the KPSC should ignore Ky. Rev. Stat. Ann. 278.2213(6) that requires dealings with affiliates to be at arm's length due to the "great value offered to ULH&P" by the net book transaction.[13] The KPSC jumped at the "unique[ ] ... proposed transaction * * * at an attractive price."[14] However, the need for purchases to cover Ohio's needs under an RFP (or some other device) is increased under the Company's plan, and Ohioans would bear the increased burden of acquiring power that the KPSC sought to avoid.

As noted above, CG&E plans to construct new generating facilities for service in Ohio and to recover the costs of the facilities from Ohio customers. The Company rationalizes its plan to impose the cost of newly constructed power plants on Ohioans by pointing to a shortfall in generation resources to supply CG&E's Ohio customers. This shortfall is exacerbated by the Company's proposed sale of facilities at a depreciated "net book" price. The Kentucky Commission might be less ready to approve the purchase from CG&E if the price paid by ULH&P is set to recognize the contribution made by Ohioans towards payment for the power plants over the years. The benefit of the sale to Kentuckians is offset by the loss experienced by Ohioans. A sale for the benefit of Kentucky's electric customers at a bargain price is not in the public interest when the *entire* public, including Ohioans, is considered.

---

[13] *In re Application of ULH&P for Approval of its Acquisition of Generation Resources*, KPSC Case No. 2003-00252, ULH&P Brief at 45 (November 19, 2003).

[14] Application, Exhibit D-3 [KPSC Case No. 2003-00252, Order at 11 ("Need for an RFP") (December 5, 2003)]. The KPSC compared "the average depreciated cost of the generating units included in the offer ... [at] $332 per kw of capacity" and installed costs of "$350 to $400 per kw for CTs and $1,000, or more, per kw for base load coal-fired capacity." *Id.*

3. The Sale of Generating Assets to ULH&P Violates Ohio Law and Harms Competitive Conditions.

The Company incorrectly states in its Application and its Supplement that, "[w]ith the exception of the KPSC which has issued its approval, no state or federal commission (other than this Commission), has jurisdiction over the Transfer."[15] The Ohio Commission retains jurisdiction over a CG&E "corporate separation plan" that applies to the three generating facilities that are the subject of the sale to ULH&P.

As part of an electric transition plan case before the PUCO, CG&E entered into stipulations on May 8, 2000 with the OCC and other parties that were accepted, in principal part, by the Ohio commission. The PUCO order states: "CG&E notes that its corporate separation financing plan provides for a program to complete the transfer of its generating assets to an EWG by December 31, 2004 …."[16] The order also states that the PUCO would conduct a "periodic Commission review of the interim separation plan …."[17] The Application in the instant case, filed on September 30, 2004, would violate CG&E's corporate separation plan in Ohio by selling three of CG&E's generating facilities to ULH&P rather than to an exempt wholesale generator ("EWG"). The OCC, as one of the parties to the stipulation signed by CG&E in 2000, is contemplating the initiation of a proceeding against CG&E at the PUCO regarding enforcement of CG&E's separation plan.

---

[15] Application, Item 4; Supplement at 9, Item 4.

[16] *In re CG&E Electric Transition Plan*, PUCO Case No. 99-1658-EL-ETP *et al.* at 46 (August 31, 2000).

[17] *Id.* at 47.

CG&E recently applied to the Ohio Commission for various regulatory approvals. It unsuccessfully argued that the PUCO lacks authority over the disposition of CG&E's generating facilities.

> CG&E claims that the Commission does not possess the statutory authority to require CG&E to divest its generation assets. * * * We find no merit to this assignment of error. Clearly the Commission has the statutory authority to require CG&E to implement a corporate separation plan. * * * We further noted that we would closely monitor the implementation of the plan and take appropriate steps where we found competitive inequality, unfair competitive advantage, or abuse of market power. In addition, CG&E fully acknowledged these statutory requirements and the Commission's authority to approve a utility's corporate separation plan on pages 51-53 of its initial brief supporting the ETP stipulation. *It is disingenuous for CG&E now to argue that the Commission lacks statutory authority over an electric utility's separation of generation assets.* * * * The Commission's approval of CG&E's proposed *delay in the implementation of its corporate separation* remains conditional, being now conditioned on CG&E's acceptance of the Commission's modifications and clarifications set forth in this entry on rehearing. CG&E's ninth assignment of error is denied.[18]

CG&E's obligation in Ohio to transfer generating facilities to an EWG has been *delayed*, not terminated. It was disingenuous for the Company to state in its September 30, 2004 Application that the PUCO does not have jurisdiction over the disposition of its generating facilities.[19] The Company's statement in its January 19, 2005 Supplement that "no state or federal commission (other than this Commission [and the KPSC]), has

[18] *In re CG&E Post Market Development Period Service*, PUCO Case No. 03-93-EL-ATA *et al.*, Entry on Rehearing at 14-16, ¶16 (November 23, 2004) (emphasis added) (attached).

[19] The Application also contains an opinion by the Associate General Counsel for Cinergy Corp. that "[a]ll state laws applicable to the Applicants' involvement in the proposed transactions will be complied with." Application, Exhibit F. CG&E is subject to the enforcement authority under both Ohio Rev. Code Ann. §4928.18 (Anderson 2000) and Ohio Rev. Code Ann. §4928.36 (Anderson 2000) regarding violation of PUCO orders regarding CG&E's separation plan that is contained within CG&E's transition plan.

jurisdiction over the Transfer"[20] -- after CG&E was rebuked on the matter by the PUCO in November 2004 -- is incredible.[21]

The Company's multi-state proposal will not maintain "competitive conditions" as required by Section 12(d) of PUHCA. As stated above, the Company does not own sufficient generation resources to provide service to its retail customers. The Company agreed to transfer CG&E's generation facilities to an EWG in 2000. Ohio Rev. Code Ann. 4928.14 (Anderson 2000) provided for the competitive bidding of CG&E's retail load in Ohio by the end of 2005. The Kentucky Commission was "deeply concerned about the less-than-arm's-length relationship between ULH&P and its affiliated wholesale supplier."[22] Instead of transferring plants to an EWG that could bid on the load in Ohio and Kentucky (and without building any generating plants for ULH&P to satisfy the KPSC), the Company plans to provide ULH&P with power plants so that ULH&P does not need to purchase power. The sale will prevent the ULH&P load from

---

[20] Application, Item 4; Supplement at 9, Item 4.

[21] The Ohio requirements are well known by the KPSC.

> [CG&E] selected a Corporate Separation Plan under which its electric generating assets will be transferred to an EWG. CG&E's Corporate Separation Plan was incorporated into its restructuring Transition Plan, which has been approved by the Public Utilities Commission of Ohio. Under PUHCA, the EWG that acquires CG&E's generating assets is prohibited from selling power to ULH&P unless this [Kentucky] Commission enters certain findings of fact to authorize the EWG's power sales to ULH&P.

In the Matter of the Application of the Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C. §79Z, KPSC Case No. 2001-058 at 11 ("EWG Approval") (citations omitted). The KPSC continued to note its concern over the generation supply arrangement with CG&E, and accepted a settlement that committed ULH&P to study "the acquisition of generating assets." *Id.* at 12 ("ULH&P's Future Generating Sources").

[22] *In the Matter of the Application of the Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C. §79Z*, KPSC Case No. 2001-058 Order at 13 ("ULH&P's Future Generating Sources").

being served by alternative suppliers. The Company also proposes that CG&E own additional, high cost plants to serve its Ohio customers without engaging in any competitive bidding. The strategy is anti-competitive, and the Commission should deny the Company's proposals under Section 12(d) of PUHCA to maintain competitive conditions to protect consumers.

IV. ISSUES IN DISPUTE

The Commission should not grant or permit the proposal contained in the Company's Application and Supplement to become effective. If the Commission sets the matter for hearing, the following issues of law and fact should be viewed as disputed between the OCC and the Company:

- Does the proposed sale violate Kentucky and/or Ohio law (including prior decisions by the PUCO)?
- What is the proper "consideration," under Section 12(d) of PUHCA, that should be given for the sale of the generating plants considering the relative payments made over time by customers in Ohio and Kentucky for use of the three plants?
- Is the sale of the generating plants in the "public interest," under Section 12(d) of PUHCA, for Ohio and Kentucky consumers?
- Does the sale of the three generating plants provide for "maintenance of competitive conditions" under Section 12(d) of PUHCA?

The plan proposed by the Company should not be approved until it is thoroughly examined regarding its effects on Ohio's residential customers who are represented by the OCC.

V. CONCLUSION

The OCC's timely filing of its intervention and protest in the above-captioned docket, along with supporting arguments, entitles the OCC to participate in these proceedings. The OCC can provide insights into the consequences related to the Company's Application that have not been revealed and explained by the Company.

The approximately 600,000 residential customers in Ohio served by CG&E have paid for service from CG&E's generating facilities, including the three that the Company proposes to sell to ULH&P. These Ohio customers should not be asked to pay for expensive, new generating facilities while the depreciated plants paid for by Ohioans are sold to serve Kentucky customers at lower costs. The Application should be rejected.

WHEREFORE, the OCC respectfully requests that its Motion to Intervene in this proceeding be granted and that the Company's requested sale of CG&E's generating facilities to ULH&P be rejected as filed.

Respectfully submitted,

The Office of the Ohio Consumers' Counsel

Janine L. Migden-Ostrander
Consumers' Counsel

Jeffrey L. Small

Jeffrey L. Small, Counsel of Record
(Ohio Supreme Ct. No. 0061488)
Assistant Consumers' Counsel
Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485
Telephone: (614) 466-8574
Fax: (614) 466-9475
small@occ.state.oh.us

CERTIFICATE OF SERVICE

I hereby certify that a copy of the OCC's *Motion to Intervene and Protest* was served on the person(s) stated below via first class U.S. Mail, postage prepaid, this 14th day of February 2005.

Jeffrey L. Small
Assistant Consumers' Counsel

George Dwight II, Esq.
Cinergy Corp.
139 East Fourth Street, 25 AT2
Cincinnati, Ohio 45202
gdwight@cincergy.com

William C. Weeden, Esq.
Skadden Arps Slate Meagher & Flom
1400 New York Avenue, N.W.
Washington, D.C. 20005
wweeden@skadden.com

ATTACHMENTS

In re CG&E Post Market Development Period Service, PUCO Case No. 03-93-EL-ATA *et al.*, Entry on Rehearing (November 23, 2004).

In re New CG&E Power Plant, PUCO Case No. 04-1811-EL-AAM *et al.*, Application (December 2, 2004).

In re Application of ULH&P for Approval of its Acquisition of Generation Resources, KPSC Case No. 2003-00252, ULH&P Brief (November 19, 2003).

In re CG&E Electric Transition Plan, PUCO Case No. 99-1658-EL-ETP et al., Order at 46 (August 31, 2000).

In the Matter of the Application of the Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C. §79Z, KPSC Case No. 2001-058, Order (May 11, 2001).

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify Its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period.	)	Case No. 03-93-EL-ATA
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest Independent Transmission System Operator.	)	Case No. 03-2079-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital Investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective after the Market Development Period.	)	Case No. 03-2081-EL-AAM Case No. 03-2080-EL-ATA

ENTRY ON REHEARING

The Commission finds:

(1) The applicant, The Cincinnati Gas & Electric Company (CG&E), filed applications in these matters to modify its nonresidential generation rates to provide for market-based standard service offer pricing and to establish an alternative competitive-bid process subsequent to the end of the market development period (MDP), to permit it to defer costs and investments, and to establish a rider to recover certain capital investments.

(2) On September 29, 2004, the Commission issued its opinion and order (opinion and order) in these proceedings. In the opinion and order, the Commission approved, with certain modifications, a stipulation (stipulation) filed by some of the parties in the cases (signatory parties), including CG&E; staff of the Commission (staff); FirstEnergy Solutions Corp. (FES); Dominion Retail, Inc. (Dominion); Industrial Energy Users-Ohio (IEU); Green Mountain Energy Company (GMEC); Ohio Energy Group, Inc. (OEG); The Kroger Co. (Kroger); AK Steel

Corporation; Cognis Corp. (Cognis); People Working Cooperatively (PWC); Communities United For Action; and Ohio Hospital Association (OHA). Parties that did not sign the stipulation (nonsignatory parties) include Ohio Consumers' Counsel (OCC); Constellation NewEnergy Inc. (Constellation); MidAmerican Energy Company (MidAmerican); Strategic Energy, LLC (Strategic); WPS Energy Services, Inc. (WPS); Constellation Power Source, Inc. (CPS); Ohio Partners for Affordable Energy (OPAE); The Ohio Manufacturers' Association (OMA); National Energy Marketers Association; and PSEG Energy Resources & Trade LLC. (Constellation, MidAmerican, Strategic, and WPS may be referred to collectively as Ohio Marketers Group (OMG).)

(3) The stipulation provided, *inter alia*, for the establishment of a rate stabilization plan for CG&E that would govern the rates to be charged by CG&E from January 1, 2005, through December 31, 2008 (with certain aspects of those rates also extending through the end of 2010). The opinion and order approved the stipulation while making a number of modifications to its content.

(4) Section 4903.10, Revised Code, states that any party to a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission within 30 days of the entry of the order upon the Commission's journal.

(5) On October 29, 2004, CG&E, OCC, OMG, and CPS filed applications for rehearing.

(6) In its application for rehearing, CG&E requests, in the alternative, that the Commission either (a) reinstate the stipulation without modification, (b) adopt CG&E's suggestions, as described in its application for rehearing, or (c) "acknowledge and approve CG&E's statutory right to implement its previously-filed market-based standard service offer." (CG&E's application for rehearing at 2.) CG&E also sets forth twelve additional assignments of error that relate to the Commission's consideration and modification of the stipulation in the opinion and order. Thus, CG&E's application for rehearing actually sets forth thirteen assignments of error, as follows:

(a) In CG&E's first assignment of error, it contends that the Commission erred in failing to adopt the stipulation without modification and requests that the Commission consider modifying the opinion and order on the basis of its suggestions.

(b) In CG&E's second assignment of error, it contends that the Commission erred in purporting to establish the amount of the market price that CG&E charges for its market-based standard service offer (MBSSO), including the price to compare and provider of last resort (POLR) components and by retaining authority to approve increases or decreases in the MBSSO through annual rate reviews.

(c) In CG&E's third assignment of error, it contends that the Commission erred in finding that additional regulatory transition charges (RTCs) proposed in the stipulation to be assessed against residential consumers during 2009 and 2010 would conflict with the stipulation and recommendation approved in *In the Matter of the Application of The Cincinnati Gas & Electric Company for Approval of its Electric Transition Plan, Approval of Tariff Changes and New Tariffs, Authority to Modify Current Accounting Procedures, and Approval to Transfer its Generating Assets to an Exempt Wholesale Generator*, Case No. 99-1658-EL-ETP et al. (August 31, 2000) (*ETP* opinion), while requiring CG&E to maintain a stable generation rate for those consumers after the MDP.

(d) In CG&E's fourth assignment of error, it contends that the Commission erred in denying CG&E accounting deferrals and recovery of such deferrals through a rider amortized over a five-year period, from July 1, 2004, through December 31, 2005, related to its net capital investment to CG&E's distribution plant made on behalf of residential consumers.

(e) In CG&E's fifth assignment of error, it contends that the Commission erred in permitting all consumers to avoid POLR charges, thereby requiring CG&E to further subsidize the competitive retail electric market.

(f) In CG&E's sixth assignment of error, it contends that the Commission erred in not permitting CG&E to recover all of its POLR costs.

(g) In CG&E's seventh assignment of error, it contends that the Commission erred in denying CG&E recovery of POLR costs based upon the concept of rate shock without any evidence of record.

(h) In CG&E's eighth assignment of error, it contends that the Commission erred in permitting up to 50 percent of nonresidential consumers to avoid payment of the rate stabilization charge (RSC) of the POLR charge without CG&E's consent.

(i) In CG&E's ninth assignment of error, it contends that the Commission erred in attempting to compel CG&E either to accept the Commission's modifications of the stipulation or to take a variety of specified actions.

(j) In CG&E's tenth assignment of error, it contends that the Commission erred in attempting to determine CG&E's MBSSO by capping the price based on CG&E's cost instead of permitting a market price.

(k) In CG&E's eleventh assignment of error, it contends that the Commission erred in failing to approve CG&E's applications in these proceedings on a timely basis and in ruling only on the rate stabilization service requested by the Commission and offered as a settlement by CG&E.

(l) In CG&E's twelfth assignment of error, it contends that the Commission erred in failing to approve CG&E's MBSSO proposed on January 10, 2003.

(m) In CG&E's thirteenth assignment of error, it contends that the Commission erred in failing to acknowledge CG&E's rights to implement market rates and in failing to approve the market-based rates for which CG&E applied on January 10, 2003.

(7) OCC sets forth twelve assignments of error in its application for rehearing, as follows:

(a) OCC's first seven assignments of error relate to its contention that the stipulation, adopted by the opinion and order, violates important regulatory principles and practices. In OCC's first assignment of error, it contends that the Commission erred in failing to review alleged side agreements between individual parties, resulting in an inadequate review of the standard service offer (SSO).

(b) In OCC's second assignment of error, it contends that the Commission erred in allowing certain non-bypassable charges.

(c) In OCC's third assignment of error, it contends that the Commission erred in failing to price noncompetitive services through a statutory rate case.

(d) In OCC's fourth assignment of error, it contends that the Commission erred in allowing an SSO that is not a market-based rate.

(e) In OCC's fifth assignment of error, it contends that the Commission erred in failing to include a competitive bidding process.

(f) In OCC's sixth assignment of error, it contends that the Commission erred in failing to require CG&E to transfer its generation assets to a separate affiliate.

(g) In OCC's seventh assignment of error, it contends that the Commission erred in approving rates that are discriminatory.

(h) OCC's next four assignments of error relate to its contention that the stipulation, adopted by the opinion and order, does not, as a package, benefit ratepayers and the public interest. In OCC's eighth assignment of error, it contends that the Commission erred in failing to consider alleged side agreements.

(i) In OCC's ninth assignment of error, it contends that the Commission erred in approving an SSO that does not result in the rate certainty that the Commission has identified as its objective in allowing for rate stabilization plans.

(j) In OCC's tenth assignment of error, it contends that the Commission erred in failing to further the Commission's objective of developing a competitive market.

(k) In OCC's eleventh assignment of error, it contends that the Commission erred in failing to require specificity in the percentage of income payment plan (PIPP), weatherization and demand side management (DSM) programs in the stipulation.

(l) OCC's last assignment of error relates to its contention that the stipulation, adopted by the opinion and order, is not a product of serious bargaining among capable, knowledgeable parties. Specifically, in the twelfth assignment of error, OCC contends that the Commission erred in failing to allow for discovery of alleged side agreements between individual parties, resulting in a stipulation that is not a product of serious bargaining among capable, knowledgeable parties.

(8) In its application for rehearing, OMG sets forth five assignments of error, as follows:

(a) In OMG's first assignment of error, it contends that the Commission erred in failing to find that shopping customers should not have to pay CG&E's POLR charges unless they actually receive generation or capacity from CG&E.

(b) In OMG's second assignment of error, it contends that the Commission erred in not allowing all customers the option of electing not to purchase rate stabilization service and to avoid the RSC and the annually adjusted component, as defined in the opinion and order (AAC).

(c) In OMG's third assignment of error, it contends that the Commission erred in not establishing a flat 60-day notice period for customers to waive the rate stabilization service and be relieved from paying the RSC.

(d) In OMG's fourth assignment of error, it contends that the Commission was unclear with regard to whether a nonresidential shopping customer that returns to CG&E would pay, for each hour of CG&E service, either CG&E's incremental cost of supplying power for the month of the customer's return or the highest hourly price during the month in question.

(e) In OMG's fifth assignment of error, it contends that the Commission was unclear as to the status of the current nonresidential shopping customers for calendar year 2005.

(9) In its application for rehearing, CPS sets forth one assignment of error. Specifically, CPS contends that the Commission erred in failing to require an immediate auction in the event that it finds the rate stabilization plan (RSP) rates to be above market PRICES.

(10) Memoranda responsive (both in support and contra) to the various applications for rehearing were filed on November 8 and November 18, 2004, by CG&E, OCC, OMG, OPAE, GMEC, Dominion, IEU, Kroger, Cognis, OHA, PWC, FES, and OEG (OEG amended its filing on November 9, 2004).[1] IEU, Kroger, Cognis, OHA, PWC, FES, and OEG indicated their support for CGE's first assignment of error.

(11) The Commission has reviewed all the arguments for rehearing and will discuss below those arguments where the Commission finds further clarification or comment is required, or where rehearing is granted. Arguments for rehearing not discussed below have been adequately considered by the Commission in its opinion and order and are being denied.

(12) CG&E's first assignment of error requests, in essence, that the Commission consider its suggested modifications of the opinion and order. CG&E's suggestions are as follows:

---

1 On November 18, 2004, OMG filed a motion for leave to supplement its memorandum contra in order to respond to certain issues discussed by GMEC and Dominion in their memoranda contra. In the interest of allowing the parties the opportunity for argument related to these issues, this motion will be granted.

(a) CG&E would retain five of the modifications required by the opinion and order; specifically, (1) the extension of the five percent residential discount through December 31, 2005; (2) the recovery of deferred distribution costs from only nonresidential consumers; (3) the termination of the recovery of RTCs from residential consumers as of December 31, 2008; (4) the calculation of a market price for returning nonresidential consumers based upon only CG&E's wholesale market costs; AND (5) the calculation of actual AAC and FPP, including both cost decreases and increases in each cost category.

(b) CG&E suggests that the Commission modify the opinion and order to provide for an infrastructure maintenance fund (IMF) charge to compensate CG&E for committing its generation capacity to serve MBSSO consumers through 2008. The SUGGESTED IMF would be equal to four percent of "little g" as a component of CG&E's POLR charge during 2005 and 2006, and equal to six percent of "little g" as a component of CG&E's POLR charge during 2007 and 2008.

(c) CG&E suggests that the cost of purchased power necessary to maintain system reliability be moved from the AAC, where it was covered in the stipulation and the opinion and order, to a separate component, which CG&E suggested designating as a system reliability tracker (SRT). The SRT would permit CG&E to apply annually to the Commission to purchase power to cover peak and reserve capacity requirements and to flow through those actual costs on a dollar-for-dollar basis.

(d) CG&E suggests that the remaining portion of the AAC, as well as the RSC, be totally avoidable for the first 50 percent of nonresidential consumer load to switch to an alternate supplier and for the first 25 percent of residential consumer load to switch to an alternate supplier, as had been ordered for 2005 by the Commission.

(e) CG&E suggests that the opinion and order be modified to increase avoidability of costs by moving the recovery of emission allowances (EAs) from the AAC (under the stipulation) to recovery as part of the fuel and economy purchased power component of the price to compare (FPP).

(f) CG&E suggests that increases in the AAC for nonresidential consumers be set at four percent of "little g" in 2005, an additional four percent in 2006, and allowing CG&E to apply for additional recovery of actual costs in 2007 and 2008, and by setting increases in the AAC for residential consumers at six percent of "little g" during 2006 and allowing CG&E to apply for additional recovery of actual costs in 2007 and 2008.

(13) The Commission has reviewed CG&E's proposed modifications of the opinion and order and believes that, with certain clarifications and revisions, the suggestions are meritorious. Therefore, rehearing will be granted on CG&E's first assignment of error. The required clarifications and revisions are as follows:

(a) The amendment to the stipulation, attached to CG&E's application for rehearing, details the involvement that it expects from the Commission in the determination of the appropriate levels for the SRT, the AAC, and the FPP in various years. As to the SRT, CG&E suggests that it would make an estimate, during the fourth quarter of each year, starting in 2004, of its load for the following year and of the purchases necessary to maintain a sufficient reserve margin. CG&E would "apply to the Commission for approval of such expenditures." (CG&E's application for rehearing, attachment 1, at 7.) Attachment 2 to CG&E's application for rehearing, on page 3, describes the timeline and mechanics for this calculation, filing, and approval. That document states that "the Commission will approve the plan or approve an agreed upon alternative."

As to the AAC, CG&E proposes that the level of the charge be preset for 2005 and 2006. The Commission's involvement in setting the level for 2007 and 2008 is described in CG&E's proposed amendment to the stipulation.

Following CG&E's filing of a schedule demonstrating its increases in "net costs incurred for homeland security, taxes, and environmental compliance during each year," Commission staff would audit CG&E's calculations. "If the Staff audit confirms CG&E's calculation, the rates shall be effective" for the following year. If staff disagrees with the calculations, a hearing would be held, to be concluded within 90 days of the original filing. (CG&E's application for rehearing, attachment 1, at 2-3.)

With regard to the FPP, CG&E would, on an ongoing basis, make quarterly filings with the Commission as to a proposed fuel and economy purchased power rate (including fuel and economy purchased power costs, a reconciliation adjustment, a system loss adjustment, and EAs). While CG&E refers to "periodic audits," it specifies no procedure for Commission review. (CG&E's application for rehearing, attachment 3, at 2.)

It is unclear, in any of these three categories of costs, the extent to which the Commission will be reviewing CG&E's expenditures in the context of its audits. In all of these cases, the Commission finds that it is therefore necessary to clarify that the Commission, in its consideration of CG&E's expenditures in these categories, will continue to consider the reasonableness of expenditures. It is not in the public interest to cede this review. Nor would it foster any rate certainty to allow all decisions of this nature to be free from Commission review of reasonableness. Therefore, the Commission will require CG&E, by September 1 of each year, to file with the Commission an application to establish the FPP, the SRT and the AAC levels for the following year (except with regard to the AAC where that amount is already established for 2005 and 2006 through our opinion and order, as modified by this entry on rehearing). CG&E's calculations will include all cost increases and decreases in all covered cost categories. The Commission will review those filings and will issue appropriate orders. The filing for 2005 should be made within ten days following the issuance of this entry on rehearing.

(b) The descriptions of the costs that are to be included in the SRT, the AAC, and the FPP are unclear as to the baseline for determination of includable cost components. "Little g" was originally determined by reference to the embedded generation cost. *ETP* opinion. That cost included certain of the items to be recovered by the SRT, the AAC, and the FPP. The Commission's modification of its opinion and order, pursuant to CG&E's first assignment of error, will clarify the baselines for these components as follows. First, at the time of CG&E's last rate case, the Commission staff determined that CG&E had sufficient generation capacity to cover all of its peak load and provider of last resort obligations. Therefore, the amount included in its approved generation cost for these obligations was zero. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Electric Rates in its Service Area*, Case No. 92-1464-EL-AIR, Staff Report (March 17, 1991), at 15. As a result, all amounts in the SRT are in excess of the cost of capacity requirements which are a part of "little g." Second, with regard to the AAC, the costs of environmental compliance, security, and tax law changes, will all be based on changes in costs since the year 2000. Third, with regard to the FPP, the amounts to be recovered for fuel, economy purchased power, and EAs are those in excess of amounts authorized in CG&E's last electric fuel component proceeding.

(c) The SRT, as proposed by CG&E in its first assignment of error, would be unavoidable by shoppers. The Commission is aware that CG&E is required to maintain adequate reserves to meet its obligation as the provider of last resort. The SRT is designed to allow the recovery of expenses related to this obligation. However, it is currently unclear how this obligation will change, if at all, following the effectiveness of "MISO Day 2" (as explained in the opinion and order). Therefore, the Commission will clarify that the SRT for 2005, the level of which will be determined based on an initial SRT filing to be made by CG&E within 30 days after the issuance of this entry on rehearing, will be unavoidable. However, the avoidability or unavoidability of the SRT for all subsequent years will be determined by the Commission in a proceeding to be commenced by CG&E within 60 days following the implementation of MISO Day 2, or by July 1, 2005, whichever is earlier.

(d) In its responsive memorandum, GMEC argues, in part, that the stipulation previously restricted the seven million dollar bill credit to residential consumers served by a competitive retail electric service (CRES) provider not affiliated with CG&E. GMEC claims that, in deleting the bill credit provision and enhancing other incentives for shopping by residential consumers, CG&E would improperly eliminate that restriction. GMEC notes that, on August 23, 2004, CG&E's affiliate, Cinergy Retail Sales, Inc., filed an application to become a CRES provider. A certificate was issued to it on October 7, 2004. GMEC argues that Cinergy's name-brand recognition poses a threat that the shopping incentives could be exhausted before other CRES providers have been given an opportunity to compete. Therefore, GMEC requests that the Commission require that all shopping incentives available to the first 25 percent of switched residential load be available only to customers served by a CRES provider not affiliated with CG&E.

The Commission disagrees with GMEC on this issue. We note that, in the *ETP* opinion, the Commission stated that CG&E's nonresidential MDP could be terminated prior to December 31, 2005, only to the extent that it did not have an affiliated retail electric generation provider. As pointed out by GMEC, on October 7, 2004, Cinergy Retail Sales, Inc., an affiliated CRES provider, was issued a certificate to provide CRES in CG&E's service territory. However, the MDP for nonresidential consumers has been ended, due to the existence of more than 20 percent shopping levels. Thus, the restriction that might have prohibited CG&E from having an affiliated CRES provider is no longer effective. As to the limitation in the stipulation on the availability of the seven million dollar bill credit only to customers of nonaffiliated CRES providers, the Commission will not require that customers of affiliates and customers of nonaffiliates be similarly distinguished. The Commission will continue to monitor the residential market.

(14) The Commission has previously determined that rate stabilization plans should provide rate certainty for consumers, provide financial stability for utility companies, and encourage the development of competition. Opinion and Order at 15; *In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period,* Case No. 03-2144-EL-ATA, Opinion and Order (June 9, 2004); *In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company,* Case No. 02-2779-EL-ATA, *et al.*, Opinion and Order (September 2, 2003) (*Dayton* opinion). The opinion and order provided adequate rate certainty for consumers in the CG&E service area. The opinion and order had modified the stipulation to require consideration of cost savings as well as cost increases, and to require Commission review of fuel and economy purchased power increases. The modifications to the opinion and order which are being made by this entry on rehearing do not change these items and, further, clarify Commission review of all annual changes to the cost components. Thus, rate certainty for consumers is being ensured.

The stipulation, as modified by the opinion and order, provided adequate assurance of financial stability for CG&E. Nothing in the proposed modifications suggested by CG&E in its first assignment of error would alter that conclusion.

The opinion and order modified the stipulation in a variety of aspects designed to encourage the development of competitive markets. First, the percentage of nonresidential consumers that can avoid the RSC and the AAC was increased by the opinion and order from 25 percent to 50 percent. Second, the opinion and order decreased the total cost of service for residential consumers by extending the residential discount until December 31, 2005; by terminating the collection of RTCs as of December 31, 2008; and by charging only nonresidential consumers for the cost of certain capital investments in CG&E's distribution system. The revisions to the opinion and order which are being made by this entry on rehearing would leave all of these modifications in place and would also make two other positive changes. First, the opinion and order will be modified to increase the price to compare for all shoppers by moving the cost of EAs from the unavoidable portion of the price to the avoidable portion for the price. Second, the opinion and order will be modified to further increase the price to compare by making the AAC permanently avoidable for a percentage of each class of consumers.[2]

Therefore, the Commission finds that the modifications of the opinion and order suggested by CG&E in its first assignment of error will provide rate certainty for consumers, will provide financial stability for CG&E, and will further encourage the development of competitive markets. CG&E's first assignment or error is therefore granted, subject to the clarifications and revisions discussed above.

(15) CG&E's second assignment of error includes two separate arguments. To the extent that it refers to annual reviews by the Commission, this issue was discussed previously in this entry. The remainder of this assignment of error is made moot by the grant of rehearing with regard to CG&E's first assignment of error.

(16) Several of CG&E's other assignments of error, including those described above as numbers three, four, five, six, seven, eight, ten, eleven, twelve, and thirteen, are also moot. Some discussion of certain aspects of the ninth assignment of error is warranted.

(a) In its ninth assignment of error, CG&E argues that the Commission's order is unjust and unlawful because it attempts to compel CG&E to divest its generation assets if CG&E does not accept the changes to the stipulation required by the Commission's opinion and order. CG&E

2 Dominion and Green Mountain both complained that the deletion of the provision in the stipulation which would have provided seven million dollars in bill credits for residential consumers would harm competition. The analysis by Dominion and Green Mountain is discussed and challenged in certain respects by OMG in its supplement to its memorandum contra. The Commission finds that the modifications to the opinion and order being made by this entry on rehearing provide sufficient other incentives for shopping by residential consumers that the loss of these bill credits is not unreasonably unsupportive of the development of competition.

claims that the Commission does not possess the statutory authority to require CG&E to divest its generation assets. It claims that Section 4928.17(E), Revised Code, permits CG&E to determine whether it will, or will not, divest its generation assets. CG&E also claims that it is not bound by the stipulation approved by the Commission in the *ETP* opinion because all parties, including CG&E, have the statutory right to seek an amendment to CG&E's corporate separation plan. CG&E claims that it applied for, and the Commission has approved, such an amendment, as part of the stipulation, modified or otherwise.

(b) We find no merit to this assignment of error. Clearly the Commission has the statutory authority to require CG&E to implement a corporate separation plan. Section 4928.17(A), Revised Code, provides that no electric utility shall engage, either directly or through an affiliate, in the businesses of supplying both a noncompetitive retail electric service and a competitive retail electric service unless the utility implements and operates under a corporate separation plan that is approved by the Commission. Section 4928.17(A)(1), Revised Code, further provides that the plan must provide, at a minimum, for the provision of the CRES or the nonelectric product or service through a fully separated affiliate of the utility. Pursuant to these statutory requirements, CG&E filed an application for, and the Commission approved, CG&E's corporate separation plan in the *ETP* opinion. Under that order, we found that good cause existed to allow the separation of CG&E's generation assets as proposed by CG&E to occur by December 31, 2004. We found that this satisfied the public interest in preventing unfair competitive advantage and preventing the abuse of market power. We further noted that we would closely monitor the implementation of the plan and take appropriate steps where we found competitive inequality, unfair competitive advantage, or abuse of market power. In addition, CG&E fully acknowledged these statutory requirements and the Commission's authority to approve a utility's corporate separation plan on pages 51-53 of its initial brief supporting the *ETP* stipulation. It is disingenuous for CG&E now to argue that the Commission lacks statutory authority over an electric utility's separation of generation assets.

(c) As a part of the stipulation, CG&E sought Commission approval of a delay in the implementation of its corporate separation plan. CG&E has argued that any party has the right to file an application seeking to amend CG&E's corporate separation plan. We do not disagree. However, all such applications for amendments are subject to the approval of the Commission. Absent Commission approval, no such amendment is authorized. In addition, while CG&E is correct that the Commission approved a delay in the implementation of CG&E's corporate separation as part of our opinion and order, we did so as part of a package of modifications to the stipulation that we found to be appropriate and in the public interest. We further noted that, if the company did not implement the stipulation as revised by the opinion and order, then full separation should be established as directed by, and under the time frames established in the *ETP* opinion. The Commission's approval of CG&E's proposed delay in the implementation of its corporate separation remains conditional, being now conditioned on CG&E's acceptance of the Commission's modifications and clarifications set forth in this entry on rehearing. CG&E's ninth assignment of error is denied.

(17) In its application for rehearing, OCC included three assignments of error (numbers one, eight, and twelve) that relate to the Commission's refusal to require discovery of side agreements. As the Commission has previously confirmed, side agreements, being information related to the negotiation of a proposed stipulation, are privileged and therefore not discoverable. *Dayton* opinion, at 13-14. In addition, even if it were not privileged, information relating to side agreements is not relevant to the determination of this matter. As stated in the *Dayton* opinion, "the Commission would note that no agreement among the signatory parties to the stipulation can change the terms of the stipulation. Either the terms of the

stipulation are, on their face, beneficial to the ratepayers and the public or they are not. Even if there were side agreements among the signatory parties, those agreements would not change the public benefit or detriment of the stipulation." *Dayton* opinion at 14. Rehearing on these grounds is denied.

(18) OCC's second assignment of error and OMG's first and second assignments of error relate to their argument that the Commission should not have allowed certain non-bypassable charges. They claim that the AAC and the RSC should be avoidable. The Commission, as described above, has found that the stipulation, as modified and clarified by the opinion and order and this entry on rehearing, benefits consumers as a package. In addition, the Commission notes that the avoidability of the SRT will be specifically considered during 2005. Rehearing on these grounds is denied.

(19) In OCC's third assignment of error, it argues that the Commission unreasonably and unlawfully established a procedure to increase the AAC that does not meet the requirements of Section 4928.15, Revised Code. OCC claims that the AAC is a noncompetitive service under Section 4928.01(B), Revised Code. As a result, OCC contends that Section 4928.15, Revised Code, requires that noncompetitive services be priced through Section 4909.18, Revised Code. Further, OCC claims that, because the AAC charge is meant to increase rates, Section 4909.18, Revised Code, requires a full review of the company as conducted in a traditional rate case. We find no merit to this assignment of error. Section 4928.15, Revised Code, provides that no electric utility shall supply noncompetitive retail electric distribution, transmission, or ancillary service in this state except pursuant to a schedule for that service that is filed with the Commission under Section 4909.18, Revised Code. The AAC, about which OCC is complaining, is not a charge placed upon distribution or transmission, and is not an ancillary service. Thus, a traditional rate case review under Section 4909.18, Revised Code, is inapplicable.

In addition, the Commission has found, and finds in this entry on rehearing, that the stipulation, as modified by the opinion and order and by this entry on rehearing, is not unreasonable as to the amount to be charged under the AAC. Section 4928.14, Revised Code, provides that competitive retail electric services, including a firm supply of electric generation service, shall be provided to consumers at market-based rates, rather than establishing such charges through the traditional rate-based approach under Section 4909.18, Revised Code. Thus, the statutory requirement for the Commission, and what is provided under the stipulation as modified, is to ensure that CG&E's generation rates are market-based. In this case, the AAC is a part of CG&E's competitive electric generation charge, which we have previously determined to be a market-based rate. Accordingly, we deny this portion of OCC's application for rehearing.

(20) OCC's fourth and fifth assignments of error are also denied. The Commission found, in its opinion and order, that the price under the stipulation is market-based. The Commission noted that the governing statute allows for flexibility in the determination of such charges and that the stipulation satisfied the statutory requirements. As to competitive bidding, the Commission found that the stipulation offered a reasonable alternative to a traditional process. The stipulation, as futher modified by this entry on rehearing, meets these two requirements no less than did the stipulation as filed.

(21) OCC's sixth assignment of error relates to its belief that CG&E's generation assets should be transferred to a separate affiliate. This topic was discussed fully above. Rehearing is denied.

(22) OCC's seventh assignment of error states that the rates approved are discriminatory. The Commission has previously found that any residential consumer has the opportunity to become a part of the group that can receive shopping incentives. Opinion and order at 28. Therefore, there is no discrimination. Rehearing on this ground is denied.

(23) OCC's ninth and tenth assignments of error relate to its argument that the stipulation does not result in rate certainty or the development of competition. The Commission has fully discussed these issues in this entry on rehearing, as well as in the opinion and order. Rehearing on these grounds is denied.

(24) OCC's eleventh assignment of error states that more specificity should have been required in CG&E's plans regarding the PIPP, weatherization and DSM programs. The Commission notes that CG&E agreed to extend its current programs regarding weatherization and energy assistance. This is sufficient "detail." As to DSM programs, CG&E committed that it would work to develop such programs in a collaborative process. The Commission finds this approach to be reasonable. Therefore, rehearing on this ground is denied.

(25) In OMG's application for rehearing, its third assignment of error states that the Commission should have established a flat, 60-day notice for waiver of the rate stabilization service. CG&E, in its memoranda contra OMG's application for rehearing, states (at page 7) that "in the spirit of compromise [it] agrees to a flat 60-day notice provision as requested by OMG." However, CG&E suggests that the notice may be provided to CG&E starting on December 15, 2004. The Commission finds that notice cannot be given in time for a consumer to bypass the RSC and the AAC by the beginning of 2005. Therefore, the Commission will grant rehearing as follows: (a) the opinion and order is modified to allow a flat 60-day notice period; (b) notices may be given to CG&E any time after the issuance of this entry on rehearing; and (c) for those consumers wishing to avoid the RSC and the AAC as of any date between January 1, 2005, and January 24, 2005 (for whom a 60-day notice is impossible), notice to CG&E by December 15, 2004, shall be considered timely. The Commission further finds that CG&E should inform the Commission, within three days following the issuance of this entry on rehearing, as to the process it will employ to ensure that all nonresidential customers that may be affected by these provisions will be notified of these deadlines.

(26) OMG's fourth assignment of error requests clarification of the cost to be charged to returning, nonresidential shoppers. In CG&E's memorandum contra OMG's application for rehearing, CG&E states that such customers would pay "the highest hourly cost of power for each hour during which CG&E served the consumer." To the extent that the opinion and order was unclear on this point, rehearing is granted on this ground. CG&E will charge any returning, nonresidential shopper, for each hour it provides service to the returned shopper, the highest hourly cost of power that CG&E incurs for that hour. That highest hourly cost of power could, therefore, fluctuate on an hourly basis. For customers without time-of-day meters, CG&E should work with staff to develop an appropriate process to calculate such charges.

(27) OMG's final assignment of error requests clarification of the status of current nonresidential shopping customers for the calendar year 2005. CG&E responds that it would be inequitable and unlawful to require CG&E "to further subsidize the shopping consumers by permitting shopping consumers who are switched as of December 31, 2004, and receiving shopping credits during 2005, to avoid the RSC or the AAC during 2005." The Commission agrees with OMG. The RSC and the AAC, as well as the SRT (which covers cost

components that were a part of the AAC as discussed in the opinion and order), should be avoidable by current, nonresidential shopping credit customers during 2005. The Commission finds that this will encourage further development of the competitive market.

OMG also requested that nonresidential consumers who are receiving shopping credits be allowed to give notice to CG&E of their intent to avoid the RSC and AAC effective January 1, 2006. The Commission finds that notice of intent to avoid the RSC and the AAC could be given well in advance of January 1, 2006, based on a consumer's execution of the appropriate contract with a CRES provider. Rehearing on this ground is therefore granted.

(28) In its application for rehearing, CPS argues that the opinion and order should be amended to state that, if the Commission at any time finds the RSP to be a non-market rate, the Commission on its own may call for a bid-out to be conducted pursuant to Section 4928.14(B), Revised Code. As discussed in our opinion and order, Section 4928.14(B), Revised Code, provides that the Commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers are readily available in the market and a reasonable means for customer participation is developed. The opinion and order further found that the procedure established by the stipulation offers a reasonable alternative to a more traditional competitive bidding process, provides for a reasonable means of customer participation through the various options that are open to customers under the RSP, and fulfills the statutory requirements for a competitive bidding process. Further, we note that, under paragraph 13 of the stipulation, the "parties agree that the Commission may determine and implement a competitive bidding process to test CG&E's price to compare." Accordingly, the Commission retains the authority under the stipulation to implement a competitive bidding process at any time. CPS's application for rehearing is therefore denied.

It is, therefore,

ORDERED, That the motion by OMG for leave to file a supplement to its memorandum contra be granted. It is, further,

ORDERED, That the application for rehearing filed in this matter by CG&E be granted in part and denied in part. It is, further, ORDERED, That the application for rehearing filed in this matter by OCC be denied. It is, further,

ORDERED, That the application for rehearing filed in this matter by OMG be granted in part and denied in part. It is, further,

ORDERED, That the application for rehearing filed in this matter by CPS be denied. It is, further,

ORDERED, That the stipulation be approved, to the extent and subject to the modifications and clarifications set forth in the September 29, 2004, opinion and order in these proceedings, as further modified by this entry on rehearing. It is, further,

ORDERED, That a copy of this entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones

Donald L. Mason

Clarence D. Rogers, Jr.

JWK/SEF;geb

Entered in the Journal
NOV 2 3 2004

Reneé J. Jenkins
Secretary

20

FILE

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter of the Application of The Cincinnati Gas & Electric Company for Approval to Defer for Subsequent Recovery Post-In-Service Carrying Costs and Depreciation Costs Associated with Capital Investment in As Yet Undetermined Generating Facilities to be Purchased or Built by CG&E Pursuant to Certain Approved Parameters	)	Case No. 04-1811-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company For Approval to Recover Capital Investment And Related Costs Associated with Purchase or Construction Of As Yet Undetermined Generating Facilities Through its System Reliability Tracker Through 2008 and Through a Non-bypassable Market-Based Standard Service Offer Charge After 2008	)	Case No. 04-____-EL-UNC
In the Matter of the Application of The Cincinnati Gas & Electric Company For Approval to Modify Accounting Practices to Permit a Return on Purchased Power Agreements	)	Case No. 04-____-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company For an Amendment to its Corporate Separation Plan Provided for in the Stipulation and Recommendation in its Electric Transition Plan Case To Own As Yet Undertermined Generating Facilities	)	Case No. 04-____-EL-ETP

135020

APPLICATION

TO THE HONORABLE
THE PUBLIC UTILITIES COMMISSION OF OHIO:

1. The Cincinnati Gas & Electric Company (CG&E) is an Ohio corporation engaged in the business of supplying electric transmission, distribution, and generation service in Adams, Brown, Butler, Clinton, Clermont, Hamilton, Montgomery, and Warren Counties in Southwestern Ohio to approximately 642,000 consumers, and supplying electric transmission and distribution service to approximately 23,000 consumers that receive generation service from Competitive Retail Electric Service (CRES) Providers, all of whom will be affected by this Application.

2. CG&E is a "public utility" as defined by R. C. 4905.02 and 4905.03; and an "electric distribution company," "electric light company," "electric supplier," and an "electric utility" as defined by R. C. 4928.01.

3. This application is made pursuant to R. C. 4928.14 and R. C. 4909.18 for approval of certain parameters within which CG&E can purchase or build as yet undetermined generating facilities; to recover certain costs and a reasonable return on the capital investment in such generating facilities and to recover such costs and return through its system reliability tracker through 2008 and through a non-bypassable market-based standard service offer charge after 2008. If the Commission deems such an amendment is necessary, CG&E requests an amendment to its corporate separation plan provided in the stipulation and recommendation in its Electric Transition Plan case to allow it to own such generating facilities. Additionally, CG&E requests approval to recover a return on purchased power agreements.

4. CG&E's request arises from CG&E's obligation under R. C. 4928.14(A) and (C) to provide provider of last resort (POLR) service after the end of the market development period. In an Order dated November 23, 2004 in Case No. 03-93-EL-ATA, the Commission approved a rate stabilization plan (RSP) proposal submitted by CG&E as CG&E's market-based standard service offer (MBSSO). The RSP requires CG&E to provide stable rates through 2008; allows CG&E to recover its costs through various bypassable and non-bypassable charges, including a system reliability tracker; and maintains CG&E's continued ownership of generating facilities to enable it to provide such service. CG&E needs to acquire additional capacity to be able to provide adequate and reliable POLR service and to have adequate reserve margins through 2008. After the end of the RSP, CG&E will continue to be obligated to provide POLR service. Although CG&E could rely on wholesale market purchases to supply such POLR service, CG&E submits that unique market circumstances presently exist that could enable it to acquire existing generating facilities at terms that would be more stable and substantially less than the projected cost of acquiring power through the volatile wholesale market. CG&E would also be better able to provide adequate and reliable POLR service if it acquires generating facilities, due to possible transmission constraints associated with wholesale power purchases.

5. The immediate need for additional capacity arises from CG&E's obligation to provide adequate and reliable POLR service through 2008. CG&E obtains the bulk of its supply from an existing fleet of generating assets. This fleet consists of 5,082 MWs (summer-rated, including inlet cooling) of generation. Coal-fired capacity makes up the majority (82%) of CG&E's generating fleet, while 13% is natural gas-fired, and 5% is oil-

fired. CG&E's current resources portfolio is supplemented by the use of forward reliability purchases from the wholesale power market. During spring 2005, CG&E is expected to close on its sale of 1,077 MWs (summer-rated, including inlet cooling) of generation to ULH&P. CG&E's obligation to provide full requirements service for ULH&P's peak load of 854 MWs will cease at that time. This will leave CG&E with a fleet consisting of 4,005 MWs (summer-rated, including inlet cooling) of generation. Coal-fired capacity will make up the majority (90%) of CG&E's generating fleet, while 3% will be natural gas-fired, and 7% will be oil-fired. For the summer of 2005, CG&E anticipates that forward reliability purchases will provide approximately 20% of its peak load capacity needs, based on projected load growth of 2% in CG&E's certified service territory and net of switching by summer 2005, without factoring in any demand side management programs which CG&E will seek to develop and implement through a collaborative process as provided for in CG&E's alternative rate stabilization proposal approved by the Commission's November 23, 2004 Order in Case No. 03-93-EL-ATA. CG&E's on-system reserve margin for 2004 was less than 5.2%, requiring it to rely on several hundred MWs of forward purchased power during the summer of 2004 to reach an adequate reserve margin. Four percent reserves are needed to meet ECAR and NERC operating reserve requirements; at least 8% reserves are needed for normal generating unit outages and derates; and a 3% reserve component is needed to cover potential variations in load, particularly weather-induced load. For these reasons, a reserve margin of 15% to 17% is currently necessary for CG&E, and a minimum required reserve margin of 12% is anticipated when MISO Day 2 energy markets are implemented.

6. The unique market conditions favor acquiring generating facilities under the parameters requested by CG&E. Current prices in the Midwest wholesale power market reflect an oversupply situation, due in large part to merchant generation constructed over the last few years. However, this oversupply condition is expected to be temporary, primarily because many companies that invested in generation have fallen on difficult financial times, with some being forced into bankruptcy. As new investors consider investments in generation, they will be slow to risk capital until it is clear that they can earn an adequate return to compensate them for the risks. This is evident from the lack of development of new greenfield power plants and the cancellation of many power plant projects. The combination of growing electricity demand and a tremendous slowdown in power plant construction is expected to eliminate the oversupply condition over time, causing wholesale prices to rise. In addition, other factors may cause wholesale power prices to rise, including: unexpected strong economic and electricity demand growth, unexpected hot weather, even greater electricity transmission problems, rising natural gas prices, unexpected retirements of existing plants, failure to complete merchant power plants still under construction, unexpected regulatory uncertainties delaying supply response, even greater financial problems at merchant companies decreasing the liquidity in the market, and new environmental requirements. Wholesale power prices, moreover, have been extremely volatile in the recent past, with periods of generation shortages and high prices, and periods of excess power plant supply and downward price pressure. Fuel prices, especially natural gas, have been extremely volatile lately. This volatility in the wholesale market highlights the risks associated with reliance on power purchases – the potential lack of creditworthiness of key power suppliers and transmission problems adversely affecting

delivery. Wholesale power prices are likely to increase rapidly as the market recovers, due primarily to electricity demand catching up with supply.

7. Although CG&E could acquire wholesale power to meet its supply and reserve margin needs, this would subject consumers to high and volatile prices, and could impair CG&E's ability to provide adequate and reliable service due to possible problems with transmission constraints. As a result, CG&E would limit its purchase of new generating facilities to facilities where firm delivery can be assured into the Cinergy transmission system. The reason for this is that the incidence of transmission constraints in the Midwest remains high. More specifically, past Transmission Loading Relief (TLR) events indicate increasing concerns with transmission constraints – including at peak times when such disruptions may be critical. Because system loads are increasing and third parties are using the regional transmission system in new ways, these problems will continue to be aggravated until additional facilities are constructed. In fact, there currently does not appear to be yearly Available Transmission Capacity into Cinergy from any directly interconnected companies through 2007. This is evidenced by the fact that the number and MW level of MISO refusals of firm transmission service requests continues to increase.

8. Due to the unique circumstances discussed above, it is possible that in the next one to two years, some owners of generating facilities located in or near Cinergy's control area may seek to divest some of their generating assets at attractive prices. It is possible that such prices will be cost-effective for CG&E, compared to other supply-side and demand-side options available to CG&E. If such generating assets compatible with CG&E's system are ultimately offered for sale at attractive prices, CG&E would like to take

advantage of such asset sales, for the benefit of its consumers. Due to CG&E's uncertain ability to recover such costs, however, and due to the length of time required to process the instant type of proceeding, CG&E may not be able to act expeditiously to take advantage of a favorable opportunity arising from a motivated seller's desire to sell a generating facility.

9. Similarly, CG&E may have an opportunity to build a generating facility at a cost-effective price due to these conditions and government incentives to implement new environmentally friendly generating technologies such as integrated gasification combined cycle generating plants. Unless there is a process that provides CG&E with certain cost recovery and a reasonable return on its investment, CG&E may not be able to take advantage of economically favorable opportunities to maintain low POLR charges.

10. CG&E's reasons for requesting the approvals sought herein are also based on CG&E's upcoming analysis of the cost-effectiveness of acquiring generating facilities within certain parameters versus the cost-effectiveness of various other supply options, including utilizing purchased power to provided needed capacity during the RSP period and provide an adequate reserve margin during and after the RSP period. CG&E proposes to use a least-cost resource plan to determine the amount of capacity it must obtain to satisfy its reserve margin component of its POLR requirements. This analysis would be based on various assumptions including the current amount of load in CG&E's certified service territory; economic factors (inflation, growth, interest rates), environmental regulations; fuel prices; supply-side and demand-side contingencies; and environmental compliance resource costs. Based on these assumptions, CG&E expects to demonstrate a need for the amounts of capacity for the next several years, in order to provide low market-priced POLR service

during the RSP period and to meet its reserve margin POLR requirements during and after the RSP period.

11. CG&E will provide a pricing analysis relating to as yet undetermined generating facilities, using an analysis of various supply-side resource alternatives, such as EPRI's Technical Assessment Guide® ("EPRI TAG®") for up-to-date information about both conventional and advanced power generation technologies; CG&E-specific price estimates (to be provided by Cinergy engineering personnel) for combustion turbines, combined cycle units and IGCC units; a study from an outside engineering firm (Sargent & Lundy) for new pulverized coal and fluidized bed plants; and the 2001 "Repowering the Midwest" report for additional information about the costs of renewable energy options. CG&E will provide an initial screening to eliminate technologies that are not feasible in CG&E's service territory (*e.g.*, geothermal and nuclear technologies). The next screening uses economic criteria to determine the "best in class" technology within each technology class (*e.g.*, pulverized coal, combined cycle and simple cycle CTs, and renewables such as wind and solar). Finally, a further economic screen is used to select the final set of alternatives to model, along with purchased power, in order to obtain the most cost-effective source of supply for CG&E to obtain power to provide POLR service during the RSP period and to meet its reserve margin POLR requirements during and after the RSP period.

12. Based on these analyses, CG&E will propose certain parameters related to the purchase or construction of as yet undetermined generating facilities: (a) certain confidential pricing parameters, designed to ensure that any purchase CG&E makes will be consistent with a "least cost" supply option to provide POLR service during the RSP period and to meet its reserve margin POLR requirements during and after the RSP period; (b) a

volume parameter of no greater than 600 MWs (summer-rated) generating capacity; (c) a parameter limiting any purchase to vintage 2000 or newer plants; (d) a parameter requiring that any plant purchased has the capability for firm delivery into the Cinergy transmission system; and (e) a parameter requiring the plant to be of satisfactory quality, as certified by an independent engineering firm.

13. The proposed pricing parameters for the as yet undetermined generating facilities will be derived from a "breakeven analysis" – which will compare the price it would take to "beat" the various other supply options discussed above. CG&E will model various cases assuming different amounts and types of peaking capacity. From these cases, CG&E will determine the "breakeven" cost for the amounts and types of capacity that would make the overall present value revenue requirements (PVRR) the same as that of the other supply options discussed above. This breakeven analysis will be referred to as the base case for determining the pricing parameters for the as yet undetermined generating facilities. CG&E will also perform sensitivity analysis based on the assumption that wholesale power prices would be 20% lower across the board than currently projected. CG&E will derive another "breakeven" cost for the amounts and types of capacity that would make the overall PVRR the same as the other supply options discussed above. This analysis will be referred to as the downside case. In order to present the Commission with a conservative pricing parameter, CG&E proposes that the downside case breakeven prices be used to determine the parameters for the purchase price, which shall include transaction costs, and any imminent capital investment needs identified at time of purchase or construction through the due diligence process to bring the plant into good operating condition and to provide adequate transmission facilities. CG&E proposes that the base

case prices be used as price caps for certain other possible unforeseeable potential post-transaction costs that would arise from a third-party's action and be beyond CG&E's control, such as post-transaction credit risk costs associated with the seller subsequently filing a bankruptcy petition, or potential costs, such as transmission upgrades, that might be required by MISO or FERC to ensure firm delivery.

14. CG&E will request that the Commission approve in this proceeding the recovery of the following costs that would be incurred by CG&E related to the purchase or construction of the as yet undetermined generating facilities within the parameters discussed herein: the costs of any plant purchase or construction within such parameters, including transaction or construction costs; certain post-transaction capital costs that may be incurred with the purchase or construction, up to certain caps as discussed above; deferral of post-in-service carrying costs and depreciation costs associated with any capital investment related to CG&E's purchase or construction of plants within such parameters. CG&E proposes that the amount of costs to be recovered annually would be determined according to the traditional ratemaking methodology, using the rate of return approved in CG&E's prior electric distribution base rate case. CG&E further proposes that such costs would be recovered through the system reliability tracker through 2008 and through a non-bypassable market-based POLR charge after 2008.

15. In order to take advantage of the possibility of generating facilities being constructed or offered for sale as described above, CG&E requests an order from the Commission providing certain approvals as discussed herein. CG&E would only purchase or construct such generating assets if the assets were available within the parameters to be approved by the Commission in this proceeding, and as set forth herein. Such purchases or

construction would also be subject to the compatibility of the assets with CG&E's POLR requirements to its consumers, including an adequate reserve margin; to CG&E's ability to acquire or construct such assets at sufficiently attractive prices; and to negotiate a mutually acceptable asset purchase agreement. Based on the foregoing, CG&E submits that the relief requested herein would be beneficial and efficient for CG&E and its consumers, and therefore will be in the public interest.

16. CG&E also requests that the Commission allow CG&E to earn a return on long-term (over one year in duration or with a delivery date over one year from inception), fixed cost purchased power agreements (PPAs). This would permit CG&E to evaluate PPAs as a supply option on an equal footing with the "build" and "buy" supply options. This would also assist CG&E in maintaining a sound financial condition. Without these measures, CG&E would face significant costs related to PPAs, because the contracts effectively are an imputed debt that CG&E carries as "off-balance-sheet" financing that tends to overload CG&E's capital structure with debt.

17. CG&E requests this accounting treatment related to PPAs so CG&E can maintain investment grade credit ratings. CG&E's current senior unsecured debt ratings are as follows:

Rating Agency	Rating
Fitch	BBB+
Moody's	Baa1
Standard & Poor's	BBB

CG&E's credit ratings determine CG&E's cost of debt, ability to access capital markets, and cost of doing business with suppliers and trade creditors. CG&E's credit ratings therefore directly impact CG&E's rates for electric distribution service. Additionally, equity analysts base their recommendations on a company's credit ratings, among other factors, so CG&E's credit ratings directly affect Cinergy's stock price.

Credit rating agencies have, in recent years, started treating long-term, fixed cost PPAs as similar to fixed debt obligations in evaluating an electric distribution utility's credit rating, due to the likelihood that the wholesale suppliers will deliver power under the PPAs and, in turn, the utility will be required to make the fixed payments required under the PPAs. Credit analysts also apply a risk factor when evaluating PPAs. This methodology allows credit rating agencies to better evaluate the credit of vertically integrated utilities versus merchant energy companies, and companies that build generation versus companies that buy power through PPAs. This credit evaluation methodology is extensively discussed in a Standard & Poor's research report issued May 8, 2003 entitled: "'Buy versus Build': Debt Aspects of Purchased-Power Agreements," a copy of which is at Attachment 1.

The credit rating agencies determine a company's credit ratings by considering, among other factors, various financial ratios such as debt to capitalization, pre-tax interest coverage and funds from operations to debt. By treating long-term, fixed cost PPAs as similar to debt, the credit rating agencies effectively require electric distribution utilities to maintain more common equity in their capital structure to maintain the same level of credit ratings, all other factors being equal. Long-term, fixed cost PPAs also present significant financial risk for electric distribution utilities, because the utilities must provide POLR service for their customers even if a wholesale supplier defaults on a PPA, and utilities face uncertainty as to whether they will be able to recover the full cost of replacement power from their customers. The Commission should allow CG&E to earn a return on PPAs to enable CG&E to maintain investment grade credit ratings and to continue providing safe, adequate and reliable electric distribution service for its consumers at reasonable rates. Finally, this requested accounting treatment would allow CG&E to evaluate the "build" versus "buy" on an equal footing as to financial and rate impacts, and to reach decisions without favoring either option.

18. CG&E's application complies with the policy of this State as set forth in R. C. 4928.02, in part because it will ensure the availability to consumers of adequate, reliable, safe, efficient, non-discriminatory and reasonably priced retail electric service and with the requirements of R. C. 4928.14 that requires CG&E to provide all of its consumers with an MBSSO that supplies all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

WHEREFORE, CG&E respectfully prays that this Honorable Commission:

(a) Accept this application for filing;

(b) Find that this application and the attachments filed herewith and incorporated herein, are in accordance with R. C. 4909.18, R. C. 4928.14 and Chapter 4928 and the Rules of the Commission;

(c) Approve the recovery by CG&E of the following costs that would be incurred by CG&E related to the purchase or construction of the as yet undetermined generating facilities within the parameters discussed herein: the costs of any plant purchase or construction within such parameters, including transaction costs; certain post-transaction capital costs that may be incurred with the purchase or construction work in progress costs related to construction, up to certain caps as discussed above; deferral of post-in-service carrying costs and depreciation costs associated with any capital investment related to CG&E's purchase of plants within such parameters;

(d) Approve the recovery of such costs by CG&E to be implemented automatically and immediately upon the beginning of construction or the closing of the sale of the plant, through the system reliability tracker through 2008, and through a non-bypassable market-based standard service offer POLR charge after 2008, the *pro forma* amounts for which will be established in this proceeding, and adjusted in later proceedings in the year following the closing date;

(d) Find that the proposed system reliability tracker MBSSO level of charges and methodology is non-discriminatory and non-predatory and therefore, just and reasonable;

(e) If the Commission deems such an amendment to be necessary, an amendment authorizing CG&E to amend its corporate separation plan to own such newly-constructed or newly-acquired generating facility beyond 2008;

(f) Approve the requested accounting treatment and the recovery of costs related to purchased power agreements as requested in paragraphs 16-17 of this application;

(g) Establish a scheduling order that provides the following timeline: initial technical conference – February 2, 2005; deadline for CG&E to file requested pricing parameters and supporting analysis – March 1, 2005; a stay of discovery until March 1, 2005, when CG&E's pricing parameters and supporting analysis will be available; a technical conference to discuss CG&E's proposed pricing parameters – March 16, 2005, and any other appropriate deadlines.

(h) Approve CG&E's application in all its parts within six (6) months of the date this application was filed pursuant to R. C. 4909.18.

Respectfully submitted,

THE CINCINNATI GAS &
ELECTRIC COMPANY

Gregory C. Ficke

Gregory C. Ficke, President

Julia S. Janson

Julia S. Janson, Secretary

VERIFICATION

STATE OF OHIO)
)
COUNTY OF HAMILTON)

I, Gregory C. Ficke, President. and I, Julia S. Janson, Secretary, of The Cincinnati Gas & Electric Company, being first duly sworn, hereby verify that the information contained in this Application is true and correct to the best of our knowledge and belief.

Gregory C. Ficke

Gregory C. Ficke

Julia S. Janson

Julia S. Janson

Sworn to and subscribed in my presence this 2nd day of December, 2004.

John J. Finnigan

Notary Public

JOHN J. FINNIGAN, JR. Attorney at Law
NOTARY PUBLIC, STATE OF OHIO
My commission has no expiration date. Section 147.03 O.R.C.

135020

Company official to be contacted
regarding the application:

John P. Steffen
Vice President, Rates
Cinergy Services, Inc.
139 East Fourth Street
Cincinnati, Ohio 45201
(513) 287-2560
e-mail: jsteffen@cinergy.com

Attorneys for applicant:

John J. Finnigan, Jr. (0018689)
Paul A. Colbert (0058582)
Michael J. Pahutski (0071248)
2500 Atrium II
P.O. Box 961
Cincinnati, Ohio 45201-0960
(513) 287-3601
e-mail: jfinnigan@cinergy.com
fax: (513) 287-3810

Attachment 1

STANDARD &POOR'S | RATINGSDIRECT

Return to Regular Format

Research:

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Publication date: 08-May-2003
Credit Analyst: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Dimitri Nikas, New York (1) 212-438-7807; Anthony Flintoff, London (44) 20-7826-3874; Laurie Conheady, Melbourne (61) 3-9631-2036

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery--and thus release from the payment obligation--is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

■ Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

■ Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build--i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%--10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

■ Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Table 1 ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	-	-	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2 ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage (x)		Adjusted pretax interest coverage (x)	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

■ Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6)	Case No. 2003-00252

RECEIVED
NOV 19 2003
PUBLIC SERVICE COMMISSION

BRIEF OF

THE UNION LIGHT, HEAT AND POWER COMPANY

The Union Light, Heat and Power Company (ULH&P) respectfully submits its Brief in the above-captioned proceeding.

Respectfully submitted,

THE UNION LIGHT, HEAT AND POWER COMPANY

Michael J. Pahutski, Trial Attorney
John J. Finnigan, Senior Counsel
The Union Light, Heat and Power Company
139 East Fourth Street
Cincinnati, OH 45201
(513) 287-3075
Fax: (513) 287-3810

Table of Contents

Table of Contents- Cont'd

Page No.

<u>**Table of Authorities**</u>

<u>Page No.</u>

<u>CASES</u>:

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6)	)	Case No. 2003-00252

BRIEF OF

THE UNION LIGHT, HEAT AND POWER COMPANY

I. OVERVIEW OF CASE

A. Summary of requested relief

On July 21, 2003, The Union Light, Heat and Power Company (ULH&P) filed an application for an Order pursuant to KY. REV. STAT. ANN. § 278.020 and 807 KY. ADMIN. REGS. 5:001 Sections 8 and 9 granting ULH&P a Certificate of Public Convenience and Necessity (CPCN) to acquire, at net book value plus transaction costs, ownership of three electric generating station facilities, the East Bend Generating Station (East Bend), Miami Fort Unit 6 (Miami Fort 6), and the Woodsdale Generating Station (Woodsdale) (collectively, the Plants), and related property from The Cincinnati Gas & Electric Company (CG&E), ULH&P's parent company (Application). Additionally, ULH&P requested approval of certain purchase power agreements with CG&E, authority to establish accounting deferrals for the recovery of transaction costs related to the acquisition by ULH&P of the Plants, and retention of profits related to off-system sales from the Plants. In accordance with KY. REV. STAT. ANN. § 278.2219, ULH&P also requested a deviation from the requirements of KY. REV. STAT. ANN. § 278.2207 and KY. REV. STAT. ANN. §278.2213(6) to allow ULH&P to become the assignee of certain affiliate contracts related to the operation of the Plants. Finally, ULH&P requested approval to terminate the current Power Sale Agreement with CG&E concurrent with its acquisition of the Plants and to continue to freeze its generation, fuel and wholesale transmission rates through 2006. On October 29, ULH&P amended this Application, modifying the relief that it sought from the Commission (Amendment; together with its Amendment, ULH&P shall refer to its Application hereinafter as its Amended Application).

B. Impetus for ULH&P's Application

ULH&P filed its Amended Application in direct response to the Commission's directive in Case No. 2001-00058.[1] In Case 2001-00058, the Commission required that ULH&P perform a "detailed analysis of constructing generation to lock in prices for the long term ... (and to) ensure that the northern Kentucky areas served by ULH&P have an assured long-term power supply at the lowest reasonable cost."[2] The Commission reinforced this directive in its Order in Administrative Case No. 387, where it stated, "While (ULH&P) has committed to filing a stand-alone IRP in 2004, the Commission

---

[1] *See* Direct Testimony of Greg C. Ficke (hereinafter Ficke) at 10.

[2] *See In the Matter of The Application of The Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C.§79Z*, Case No. 2001-00058 at 14 (Order dated May 11, 2001).

anticipates initiating a review of ULH&P's long-term power supply requirements at some earlier date" and "(t)he resource plans of ... ULH&P do not adequately address the need to provide reliable service at reasonable costs beyond the terms of their respective wholesale power contracts that expire over the next 3 to 5 years."[3]

In these Orders, the Commission recognized the risks imposed on retail customers from the volatility of the wholesale marketplace. As supported by the testimony of ULH&P's witness Mr. Turner, ownership of generating assets by regulated electric utilities is more important now than at any other time in history, providing a measure of certainty and stability for regulated utilities that simply cannot be achieved through substantial or total reliance on purchases of power in the wholesale market.[4] Both in the near term and over the long run, reduced dependence on the wholesale market is the best way to ensure a reliable and adequate supply of electricity at stable prices for ULH&P's end use customers.[5]

C. *ULH&P's due diligence*

ULH&P's development of the proposed transaction was in direct response to the Commission's directive in Case No. 2001-00058 and Administrative Case No. 387, as described above. With that directive in mind, ULH&P considered viable options for

---

[3] *See In the Matter of a Review of the Adequacy of Kentucky's Generation Capacity and Transmission System*, Administrative Case No. 387 (Order dated December 20, 2001).

[4] *See* Direct Testimony of James L. Turner (hereinafter Turner) at 4.

[5] *Id.*

securing electric generation for its customers at stable prices over the long term.[6] ULH&P analyzed the predicted market prices of wholesale power and the costs of constructing new generation to meet its needs, and also explored many alternative arrangements, including transferring various combinations of generating plants from CG&E to ULH&P.[7]

ULH&P's original Application in this proceeding requested approval to acquire "iron in the ground" in the form of low-cost, proven, reliable generating plants, directly interconnected to the Cinergy joint transmission system, and well-suited to neatly fill ULH&P's full load requirements, as well as provide optionality for future growth.[8] Subject to receiving certain regulatory commitments from the Commission, ULH&P proposes acquiring base load, intermediate and peaking capacity at original cost less accumulated depreciation (*i.e.* net book value), which is more than $600 million less, in terms of present value revenue requirement, than a full-requirements purchase power arrangement, and more than $700 million less than the cost of new construction.[9] ULH&P proposes to continue to jointly dispatch the Plants with the remainder of the Cinergy system, and proposes obtaining firm back-up power from its parent, CG&E, at

---

[6] *See* Ficke at 10.

[7] *Id.*

[8] *See generally* Application and supporting testimony.

[9] *Id.*

today's market prices.[10] Further, ULH&P has re-committed to its current generation, fuel and wholesale transmission related rate freeze through 2006.[11]

CG&E and Cinergy conditioned the availability of the Plants under the above terms on receiving certain regulatory commitments, primary of which were ULH&P's retention of all profits from off-system sales from the Plants, and present Commission approval for ULH&P to transfer the Plants back to CG&E should ULH&P not receive the ratemaking treatment ULH&P requested.[12]

D. ULH&P sweetens the deal

Prior to hearing and subsequent to discovery by the Attorney General's Office of Rate Intervention (AG) and the Commission Staff, ULH&P amended its request. ULH&P's Amendment to the Application: (1) removed the requirement for present Commission approval to transfer the Plants back to CG&E if ULH&P was not afforded the requested ratemaking treatment; (2) committed up to the first $1 million in annual off-system sales profit to its customers, with additional profit, if any, shared equally between its customers and the Company; and (3) capped transaction costs at 50% of the estimated amount.[13]

E. Intervenor's position

The AG, the only other party to the proceeding, took the following positions regarding ULH&P's Amended Application: (1) an RFP should be issued to further test

---

[10] *Id.*

[11] *See* Ficke at 6.

[12] *See generally* Application and supporting testimony.

[13] *See generally* Amendment to the Application.

the cost effectiveness of the offer; and (2) deferred tax-related balances accrued by CG&E when the Plants were operated as regulated facilities should inure to the benefit of ULH&P's customers. However, as detailed herein, these propositions are supported by neither the record in this proceeding nor the law. Adoption of either of the AG's positions would render the transaction infeasible, and cause CG&E to withdraw its offer to transfer these Plants to ULH&P.

II. RELIEF REQUESTED

In its Amended Application, ULH&P has requested the Commission to:

a. Grant ULH&P a CPCN, pursuant to KY. REV. STAT. ANN. § 278.020, and otherwise grant all necessary approvals for the acquisition of the Plants at original cost less accumulated depreciation;

b. Fix the value of the Plants for ratemaking purposes at the original cost less accumulated depreciation, in accordance with the Commission's authority granted by KY. REV. STAT. ANN. § 278.290;

c. Approve ULH&P's request for authorization to defer no more than $2.45 million of transaction costs incurred, without carrying charges, with such recovery to be amortized over five years beginning on the effective date of the Commission's Order in ULH&P's next general rate proceeding;

d. Approve certain wholesale power agreements with CG&E to provide firm back-up service to East Bend and Miami Fort 6 during periods of maintenance or forced outages (Back-up Power Sale Agreement (Back-up PSA)) and to provide for joint economic dispatch of the Plants (Purchase Sale and Operations Agreement (PSOA));

e. Grant ULH&P a waiver, in accordance with KY. REV. STAT. ANN. § 278.2219, from the requirements of KY. REV. STAT. ANN. § 278.2213(6) that its acquisition of the Plants from its affiliate, CG&E, be an arm's length arrangement;

f. Grant ULH&P a deviation, pursuant to KY. REV. STAT. ANN. § 278.2207, for certain affiliate agreements;

g. Grant ULH&P authorization to terminate its current Power Sale Agreement with CG&E effective on the closing date of the transfer of the Plants to ULH&P;

h. Find that the inclusion in base rates of the monthly capacity charges specified in the Back-up PSA, and reasonable capacity charges specified in successor back-up power supply agreements as approved by the Federal Energy Regulatory Commission (FERC) is just and reasonable; and approve such treatment of said capacity charges;

i. Find that the recovery and inclusion in ULH&P's fuel adjustment clause (FAC) of the energy charges assessed under the Back-up PSA, on a going forward basis from the date that ULH&P's next FAC on or after January 1, 2007 goes into effect, in accordance with 807 KY. ADMIN. REGS. 5:056 and applicable Commission precedent is just and reasonable; and approve such treatment of said energy charges;

j. Find that the recovery and inclusion in ULH&P's FAC of all costs of energy transfers from CG&E assessed under the PSOA, on a going forward basis from the date that ULH&P's next FAC on or after January 1, 2007 goes into effect, in accordance with 807 KY. ADMIN. REGS. 5:056 and applicable Commission precedent, is just and reasonable; and approve such treatment of said costs of energy transfers;

k. Find that the inclusion of the costs of all fuel consumed in the Plants in ULH&P's FAC from the date that ULH&P's next FAC on or after January 1, 2007 goes into effect, in accordance with 807 KY. ADMIN. REGS. 5:056 and applicable Commission precedent, is just and reasonable; and approve such treatment of said fuel costs;

l. Find in the present proceeding that ULH&P's request to retain 50% of the profits from off-system sales of energy from the Plants above $1 million annually is just and reasonable; and render a finding that the Commission sees no reason why such treatment should not be approved in ULH&P's next general rate proceeding;

m. Find that ULH&P's request for a waiver of the Commission's requirement, as set forth in Case No. 2001-00058, for ULH&P to analyze bids for purchased power in its stand-alone integrated resource plan (IRP) filed by June 30, 2004, is just and reasonable, and approve such request.

As consideration for the relief it has requested, ULH&P has made several commitments. First, ULH&P stands by its commitment to continue to freeze generation, fuel and wholesale transmission-related retail rates through December 31, 2006.[14] Second, ULH&P commits that it will not seek implementation of an environmental

[14] *See* Ficke at 6.

surcharge through the pendency of this rate freeze.[15] Third, ULH&P commits to submit to the Commission for approval all transaction documents related to ULH&P's acquisition of the Plants prior to closing the transaction.[16] It is ULH&P's intention that this transaction be fully transparent and open for complete review by the Commission in a timely manner.

III. PROCEDURAL POSTURE

ULH&P filed its Application, supported by the pre-filed Direct Testimony of eleven witnesses, with the Commission on July 21, 2003, opening this docket. On July 25, 2003, the AG filed a motion for full intervention in this proceeding. On July 29, 2003, the Commission granted the AG's motion for full intervention. On August 8, 2003, the Commission issued a procedural schedule in this proceeding, calling for two rounds of discovery to be served on ULH&P, the filing of testimony by opposing parties, and a round of discovery to be served by ULH&P. On August 20, 2003, the Commission revised its procedural schedule, setting this matter for hearing on October 29, 2003.

On August 21, 2003, ULH&P was served the Commission Staff's (Staff) first set of discovery, consisting of 181 distinct requests/subparts, as well as the AG's first set of discovery, consisting of 201 distinct requests/subparts. On September 2, 2003, ULH&P provided responses to these discovery requests.

---

[15] *See* Response of The Union Light, Heat and Power Company to First Set of Staff Interrogatories, No. 54(f).

[16] *See* Amendment to Application at 5.

On September 10, 2003, ULH&P was served the Staff's second set of discovery, consisting of 118 distinct requests/subparts, as well as the AG's second set of discovery, consisting of 97 distinct requests/subparts. On September 17, 2003, ULH&P provided responses to these discovery requests.

On September 26, 2003, the AG filed testimony of three witnesses. On October 6, 2003 ULH&P served the AG with a set of data requests focused on these witnesses' testimony. On October 6, 2003, the Staff also served the AG with discovery regarding these witnesses' testimony. On October 17, 2003, the AG provided responses to ULH&P's and the Staff's data requests.

On October 29, 2003, ULH&P filed an Amendment to its Application.[17] In summary, this Amendment reduced the extent of the relief sought by ULH&P to that described above. As described by ULH&P witness Mr. Turner at hearing, the purpose of the Amendment was to refine the proposed transaction to further clarify and enhance the benefits for ULH&P's customers.[18]

A hearing on ULH&P's Amended Application was held on October 29 and 30, 2003 at the offices of the Commission in Frankfort, Kentucky. At the hearing, nine of ULH&P's witnesses were cross-examined by the AG and the Staff, while the three AG witnesses were cross-examined by ULH&P and the Staff.

Several data requests were raised at hearing. ULH&P filed responses to these data requests on November 7, 2003.

---

[17] *See Amendment to Application* filed by ULH&P, October 29, 2003.

[18] *See* Trans. Vol. I at 16.

IV. SUMMARY OF TESTIMONY

ULH&P supported its Application with the pre-filed testimony of eleven witnesses:

Greg C. Ficke, President of ULH&P and CG&E, provided context for ULH&P's Application, and well as summarized the filing and the testimony of the remaining witnesses.[19]

Mr. James L. Turner, Executive Vice President of Cinergy Corp. (Cinergy) and Chief Executive Officer of Cinergy's Regulated Business Unit, provided a view of the current energy industry outlook, and described certain conditions that Cinergy requires must be met before it can allow the Plants to be transferred to ULH&P.[20]

Dr. Richard G. Stevie, General Manager of Cinergy's Market Analysis group, sponsored ULH&P's load forecast, and discussed ULH&P's demand side management efforts as well as other efforts of the Company to encourage customers to reduce energy demands during peak load periods.[21]

Mr. M. Stephen Harkness, Vice President of Cinergy Corp. and Chief Operations and Financial Officer of Cinergy's Energy Merchant Business Unit,[22] adopted the pre-

---

[19] *See generally* Ficke.

[20] *See generally* Turner.

[21] *See generally* Direct Testimony of Dr. Richard G. Stevie (hereinafter Stevie).

[22] Note that on October 31, 2003, Cinergy Corp. announced a reorganization of its management personnel, effective November 1, 2003. Some of the ULH&P witnesses referenced herein now have new job titles and responsibilities. Additionally, the *Energy Merchant Business Unit* has been renamed the *Commercial Business Unit*. This Brief will continue to reference ULH&P's witnesses in accordance with their job responsibilities at the time their testimony was submitted into the record, and will continue to reference the Energy Merchant Business Unit.

filed Direct Testimony of Mr. Robert C. McCarthy, describing in detail the Back-up PSA, and also explaining the PSOA and the joint economic dispatch of Cinergy's generation fleet.[23] Mr. Harkness also discussed off-system sales, and the need, or lack thereof, for issuing a request for proposal.

Mr. John J. Roebel, Vice President of Cinergy's Generation Resource Group, testified regarding the history, condition, operation and maintenance of the Plants and discussed the two affiliate agreements to be assigned to ULH&P.[24] Mr. Roebel also provided testimony regarding the costs of new generation construction, as well as projected operation and maintenance costs.[25]

Mr. H. Davis Ege, a Principal Mechanical Technical Specialist/Consultant with Burns & McDonnell Engineering Co., Inc. (Burns and McDonnell), opined on the condition of the Plants and how they have been operated and maintained by CG&E over the years, based on his personal examination of the Plants.[26]

Mr. J. Thomas Mason, Vice President of Cinergy's Fuels Origination group, provided testimony on the East Bend and Miami Fort 6 coal supply and origination of coal contracts.[27]

---

[23] *See generally* Direct Testimony of Robert C. McCarthy, as adopted by M. Stephen Harkness (hereinafter Harkness).

[24] *See generally* Direct Testimony of John J. Roebel (hereinafter Roebel).

[25] *Id.*

[26] *See generally* Direct Testimony of H. Davis Ege (hereinafter Ege).

[27] *See generally* Direct Testimony of J. Thomas Mason (hereinafter Mason).

Mr. Ronald C. Snead, Manager of Cinergy's Bulk Transmission Planning group, discussed the transmission of power from the Plants to ULH&P's distribution system, and also discussed transmission as it relates to the wholesale power agreements as well as the issue of transmission constraints.[28]

Mr. Judah L. Rose, Managing Director of ICF Consulting, testified regarding projected market prices for wholesale power, the effects of potential environmental legislation and regulation on market prices, the projected price for natural gas, and the potential market value of the Plants.[29]

Ms. Diane L. Jenner, Manager of Cinergy's Asset Planning and Analysis group, provided testimony regarding the least cost alternative means for providing ULH&P's customers a long-term, stable supply of electric generation.[30]

Finally, Mr. John P. Steffen, Vice President of Cinergy's Rate Department, testified to the estimated effect that this proposal would have on retail rates paid by ULH&P's customers, and supported the net book value of the Plants and estimated transaction costs.[31] Mr. Steffen also supported ULH&P's position on the recording of transferred accumulated deferred income tax (ADIT) and accumulated deferred investment tax credit (ADITC).[32]

---

[28] *See generally* Direct Testimony of Ronald C. Snead (hereinafter Snead).

[29] *See generally* Direct Testimony of Judah L. Rose (hereinafter Rose).

[30] *See generally* Direct Testimony of Diane L. Jenner (hereinafter Jenner).

[31] *See generally* Direct Testimony of John P. Steffen (hereinafter Steffen).

[32] *Id.*

The AG submitted the pre-filed testimony of three witnesses. Mr. David H. Brown Kinloch supported the AG's position on the need for a request for proposal (RFP).[33] Mr. Charles W. King offered testimony primarily on the conditions that CG&E placed on its willingness to transfer the Plants to ULH&P.[34] Mr. Michael J. Majoros supported the AG's position on the recording of ADIT and ADITC balances following ULH&P's acquisition of the Plants.[35]

V. ULH&P'S PROPOSED ACQUISITION OF THE PLANTS AND ITS REQUEST TO ENTER INTO THE WHOLESALE POWER AGREEMENTS ARE FULLY SUPPORTED BY THE RECORD AND SHOULD BE GRANTED AS REQUESTED.

A. The Commission should grant ULH&P a CPCN and all other authority ULH&P requires to acquire the Plants at original cost less accumulated depreciation.

1. Legal Standard

The legal standard for granting CPCNs to regulated utilities in Kentucky is embodied in KY. REV. STAT. ANN. § 278.020.[36] Although this statute does not squarely address the acquisition of existing electric generating facilities, the Commission has relied upon the authority granted to it by this statute in granting CPCNs to electric utilities for acquisition of existing electric generating facilities.[37] In granting a CPCN, the

---

[33] *See generally* Testimony of David H. Brown Kinloch (hereinafter Kinloch).

[34] *See generally* Direct Testimony of Charles W. King (hereinafter King).

[35] *See generally* Direct Testimony of Michael J. Majoros, Jr. (hereinafter Majoros).

[36] KY. REV. STAT. ANN. § 278.020 (Baldwin 2003)

[37] *See e.g. In the Matter of Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Acquisition of Two Combustion*

Commission must consider whether the public convenience and necessity require the proposed expenditure.[38] Further, the Commission has generally applied the *least cost alternative* standard in assessing a request for a CPCN.[39]

2. *Cinergy considered many factors in offering the Plants to ULH&P.*

ULH&P's development of the proposed transaction was in direct response to the Commission's directive in Case No. 2001-00058 and Administrative Case No. 387, as described above. With that directive in mind, ULH&P considered viable options for securing electric generation for its customers at stable prices over the long term.[40] ULH&P analyzed the predicted market prices of wholesale power and the costs of constructing new generation to meet its needs, and also explored many alternative arrangements, including transferring various combinations of generating plants from CG&E to ULH&P.[41]

As ULH&P's witness, Mr. Harkness, testified upon cross-examination, CG&E and ULH&P considered a variety of factors in determining which of CG&E's plants

---

Turbines, Case No. 2002-00029 (hereinafter *LG&E/KU*) (LG&E and KU applied for a CPCN to acquire ownership of two combustion turbines from a non-regulated affiliate); *In the Matter of The Application of the Kentucky Power Company for a Certificate of Public Convenience and Necessity*, Case No. 8271 (Kentucky Power applied for a CPCN to purchase a 15% undivided interest in two 1,300 MW generating units constructed in Indiana.)

[38] KY. REV. STAT. ANN. § 278.020 (Baldwin 2003) ("No person ... shall commence ... the construction of any plant, equipment, property or facility ... until that person has obtained a certificate that public convenience and necessity require the service or construction.")

[39] *See LG&E/KU* ("LG&E's and KU's analysis supports the construction of the two CTs as the least cost option for meeting loads in 2002 and 2003 compared to relying on purchase power peaking alternatives... Based on the evidence of record, the Commission finds that the acquisition of the two CTs is the least cost option to reliably serve LG&E's and KU's customer loads, is reasonable, and should be approved.")

[40] *See* Ficke at 10.

[41] *Id.*

might suit ULH&P's needs.[42] First, CG&E only considered making available to ULH&P high-quality, proven and reliable plants with a good track record, such as CG&E's "number-two prize" generating facility, East Bend.[43] CG&E also assumed that the Commission and ULH&P customers would appreciate the benefits of being served from a plant physically located in Kentucky, and that has installed a scrubber for SO_2 removal and a selective catalytic reduction (SCR) control system for NO_X removal – these factors also pointed CG&E toward East Bend.[44] Third, CG&E steered away from plants that were encumbered in some way, for instance by being co-owned by a third party which had not approved the transfer of the plants, or by being named in an EPA lawsuit.[45] Fourth, CG&E looked to plants that had good long-term operating characteristics.[46] Fifth, CG&E sought to transfer plants that would result in a balanced and stable revenue requirement for ULH&P so that the transfer of the plants would not have a significant effect on rates.[47] Finally, CG&E sought to identify plants the transfer of which would not have an unreasonable impact on Cinergy's other stakeholders and would not impair CG&E operationally and financially, particularly with respect to CG&E's credit rating.[48]

---

[42] *See* Trans. Vol. I at 115 – 118.

[43] *Id.* at 115 – 116.

[44] *Id.* at 116.

[45] *Id.*

[46] *Id.* at 117.

[47] *Id.*

[48] *Id.*

3. The record evidence supports ULH&P's proposed acquisition of the Plants as the least cost alternative.

The evidence of record conclusively establishes that ULH&P's proposed acquisition of the Plants is the least cost alternative to meet the need expressed by the Commission's mandate that ULH&P "ensure that the northern Kentucky areas served by ULH&P have an assured long-term power supply at the lowest reasonable cost."[49]

ULH&P presented the Direct Testimony of Diane L. Jenner, Manager of Asset Planning and Analysis, describing the integrated resource planning (IRP) process she employed to analyze options in determining an optimal combination of resources that can be used to reliably and cost-effectively meet ULH&P's customers' future electricity requirements.[50] Ms. Jenner considered ULH&P's load requirements, as forecasted by Dr. Stevie, as well as an adequate reserve requirement considering Operating Reserves, Load and Frequency Regulation Reserves, Spinning Reserves, unscheduled outages, and fluctuations in load caused by, among other things, unexpected weather conditions.[51]

Ms. Jenner provided uncontested testimony regarding the IRP process she employed in assessing ULH&P's proposal.[52] This IRP process involved a number of steps: (1) development of planning objectives and assumptions; (2) preparation of an electric load forecast; (3) identification and screening of potential electric demand-side resource options; (4) identification and screening of, and performing sensitivity analyses

---

[49] *See* Case No. 2001-00058 at 14.

[50] *See* Jenner at 4.

[51] *See* Jenner at 6 – 7.

[52] *See* Jenner at 9 – 10.

of, the cost-effectiveness of potential electric supply-side resources; (5) identification and screening of, and performing analysis around, the cost-effectiveness of potential environmental compliance options; (6) integration of the demand-side and supply-side and environmental compliance options; (7) performing final sensitivity analyses on the integrated resource alternatives; and (8) selecting an optimal plan based on quantitative and qualitative factors (such as risk, reliability, technical feasibility, and other qualitative factors); and use of a sophisticated, independently developed computer model, STRATEGIST®, to assist with this highly data-intensive analytical process.[53]

Ms. Jenner testified that she considered a multitude of options and combinations of options, including demand-side management (DSM) programs, peaking units, combined cycle units, coal-fired units, fuel cells, renewable resources (such as wind and solar), and power purchases in ULH&P's IRP process.[54] Ms. Jenner testified that she relied upon a variety of sources, including the Electric Power Research Institute (EPRI) Technical Assessment Guide® (TAG), Cinergy-specific cost estimates, and information from a study prepared for Cinergy by Sargent & Lundy, a well-known utility engineering and construction firm, in estimating the cost of new supply-side resource options.[55] Ms. Jenner also described the screening process and sensitivity analyses she conducted, as well as her consideration of potential environmental compliance options.[56] Finally, Ms.

---

[53] *Id.*

[54] *Id.* at 10.

[55] *Id.* at 12.

[56] *Id.* at 12 – 16.

Jenner described the specific modeling performed on the options, including the proposed acquisition of the Plants, taking into consideration the load forecast and demand-side management impacts provided to her by ULH&P witness Dr. Richard G. Stevie, fuel prices provided to her by ULH&P witnesses J. Thomas Mason and Judah L. Rose, forecasted market prices under a variety of sensitivity assumptions provided by Mr. Rose, and projected operations, maintenance, administrative and general costs provided by ULH&P witnesses John J. Roebel and John P. Steffen.[57] Ms. Jenner also considered the proposed PSOA and the Back-up PSA in her analysis.[58] Ultimately, Ms. Jenner's analysis demonstrated that ULH&P's proposed acquisition of the Plants resulted in a present value revenue requirement of $643 million less than the next best alternative, a full requirements purchase power agreement, over the study period (*i.e.* 20-year planning period plus infinite end effects).[59] This analysis assumed that ULH&P could acquire the Plants at original cost less accumulated depreciation, took into consideration the budgeted capital expenditures of the Plants, and assumed that the effect on customers would not be felt until January 1, 2007 at the earliest (in light of ULH&P's commitment to the current rate freeze).[60] Further, Ms. Jenner testified at hearing that given the Amendment to the Application, the savings to customers would be even greater.[61]

---

[57] *Id.* at 17 – 18; 23 – 24.

[58] *Id.* at 19, 23.

[59] *Id.* at 26.

[60] *Id. at* 23, 24, 25.

[61] See Trans. Vol. I at 87.

Additionally, Ms. Jenner considered several risk-related qualitative factors in assessing alternatives.[62] These included: (1) risk associated with siting and constructing new generation; (2) pricing risk; (3) non-performance risk; and (4) deliverability risk considerations associated with purchasing large amounts of power from the wholesale market from distant generating units.[63] These risks are mitigated with a plan that calls for the acquisition of on-system generating capacity by ULH&P, as opposed to a plan that relies heavily on purchased power or ownership of generating units distant from the Cinergy transmission system.[64]

Ms. Jenner's analysis was uncontested by the AG and the Staff.

4. *The Plants are in good condition and can be relied upon to provide reliable electric generation service to ULH&P's customers for many years to come.*

ULH&P presented the testimony of John J. Roebel and H. Davis Ege in support of the features and the quality of the Plants. As described by Mr. Roebel, East Bend is a 648 MW (nameplate rating) coal-fired base load unit, jointly owned by CG&E and The Dayton Power and Light Company, located along the Ohio River in Boone County, Kentucky, that was commissioned in 1981, of which CG&E owns 69%, or 447 MW.[65] East Bend has river facilities to allow barge deliveries of coal and lime, and is designed

---

[62] See Jenner at 29.

[63] *Id.* at 29 – 30.

[64] *Id.* at 30.

[65] *See* Roebel at 2 – 3.

to burn low- to high-sulfur eastern bituminous coal.[66] East Bend achieved a net plant heat rate for 2002 of 10,911 Btu/kWh and for 2003 through April achieved a net plant heat rate of 10,423 Btu/kWh.[67] East Bend has considerable pollution control features, including a mechanical draft cooling tower, a high-efficiency hot side electrostatic precipitator, a lime-based flue gas desulfurization (FGD) system and a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_X) emissions by 85%.[68] Significantly, the station's electrical output is directly connected to the Cinergy 345 kV transmission system.[69]

Miami Fort 6 is a 168 MW (nameplate rating, 163 MW net rating) coal-fired base/intermediate load unit located at Miami Fort Station along the Ohio River in Hamilton County, Ohio, that was commissioned in 1960.[70] Unit 6 is one of four coal-fired units at the Miami Fort Generating Station, which has river facilities to allow for barge delivery of coal.[71] Unit 6 is designed to burn low- to high-sulfur eastern bituminous coal and achieved a net unit heat rate for 2002 of 10,012 Btu/kWh and for 2003 through April achieved a net unit heat rate of 9,930 Btu/kWh.[72] Like East Bend, this unit is directly connected to the Cinergy high voltage joint transmission system.[73]

---

[66] *Id.*

[67] *Id.*

[68] *Id.*

[69] *Id.*

[70] *Id.* at 3 – 4.

[71] *Id.*

[72] *Id.*

Woodsdale is a six-unit combustion turbine (CT) station located in Butler County, Ohio, just north of Cincinnati, with a collective nameplate rating of 490 MW.[74] Woodsdale's net summer capacity is 500 MW due to the efficiencies associated with Woodsdale's inlet cooling capabilities.[75] Woodsdale is designed for peaking service, and it has dual fuel capability (natural gas and propane) and black start capability, *i.e.* Woodsdale has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout.[76] Further, Woodsdale is connected to two separate gas transmission companies, Texas Eastern Transmission Company (TETCO) and Texas Gas Transmission Company, that transport the natural gas to supply the Plant.[77] As with East Bend and Miami Fort 6, Woodsdale's electrical output is directly connected to the Cinergy 345 kV transmission system.[78]

As indicated above, ULH&P retained the services of Burns and McDonnell to perform an engineering due diligence of the Plants. Mr. Ege, of Burns and McDonnell, led a team of engineers in on-site tours and analyses of the Plants.[79] Mr. Ege testified that the Plants are designed and constructed in accordance with industry standards, the Plants

---

[73] *Id.*

[74] *Id.* at 4.

[75] *Id.*

[76] *Id.*

[77] *Id.* at 5.
[78] *Id.*

[79] *See* Ege at 4.

are well-maintained, and the Plants' operating staffs appear qualified and cross-trained to perform routine maintenance on the Plants.[80] Mr. Ege concluded that the Plants are capable of providing long-term reliable service.[81] Neither Mr. Roebel's nor Mr. Ege's testimony was contested by the Staff or the AG.

B. The proposed wholesale power agreements are necessary to supplement ULH&P's acquisition of the Plants and are otherwise just and reasonable.

ULH&P seeks approval of two wholesale power agreements in this proceeding, the Back-up PSA and the PSOA. Both wholesale power agreements are subject to FERC jurisdiction.[82] The Back-up PSA is designed to provide a firm supply of power for ULH&P's native load customers to replace capacity from East Bend and Miami Fort 6.[83] Some outages and de-ratings of East Bend and Miami Fort 6 are inevitable, and ULH&P will need a firm supply of back-up power when this happens.[84] The Back-up PSA provides for CG&E to sell firm power to ULH&P when such outages or de-rates of East Bend and/or Miami Fort 6 occur.[85]

The Back-Up PSA provides for a capacity charge and an energy charge, which when taken together, replicate a market price for back-up power.[86] The energy charge is

---

[80] *Id.* at 4 – 8.

[81] *Id.*

[82] *See* Ficke at 9.

[83] *See* Harkness at 3.

[84] *Id.*

[85] *Id.*

[86] *Id.* at 4.

priced at the average variable cost per MWh of energy produced during the prior calendar month at the Plant for which back-up power is required.[87] The capacity charge was determined based on valuation of power, using the forward market prices quoted from *Megawatt Daily* and off-peak prices quoted from the *North American Power 10x Report*, and on an estimate of how often ULH&P would require back-up power for East Bend and Miami Fort 6.[88] The estimate of how often ULH&P would require the back-up power was calculated by applying planned outage schedules and an equivalent forced outage rate based on historical performance for East Bend and Miami Fort 6.[89] Thus, through the Back-up PSA, ULH&P is assured a firm supply of power during outages of East Bend and Miami Fort 6 at rates calculated to replicate market pricing, a proposition unlikely to be offered by any unaffiliated entity.

The PSOA provides the terms and conditions under which ULH&P will allow the Plants to be jointly dispatched along with CG&E's and PSI Energy, Inc.'s (PSI) generating units.[90] The system dispatch provisions of the PSOA call for CG&E and ULH&P to economically dispatch their respective generating units.[91] In addition, the PSOA is designed to permit ULH&P's units to be dispatched, in effect, as CG&E

---

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.* at 7.

[91] *See* Harkness at 8.

generation for purposes of the existing Joint Generation Dispatch Agreement (JGDA), thus allowing continued joint dispatch of the generation of PSI, CG&E and ULH&P.[92]

Under the PSOA, the Plants will be dispatched no differently than they currently are under the JGDA.[93] The only real change will come in how energy transferred from CG&E to ULH&P will take place.[94] Under joint economic dispatch, ULH&P's generation may be used to serve CG&E load and vice versa, as one company's lower-cost units are used to serve some portion of the load of the other company when excess generation is available.[95] The PSOA's energy transfer provisions specify a methodology for ensuring that such energy transfers shall be at the market price for the hour in which the energy transfer takes place, but in no event shall the price of such energy transfers exceed the incremental cost of the next available generating unit of the receiving company.[96]

Even though these two wholesale power agreements are FERC jurisdictional, ULH&P requests that the Commission formally recognize the benefits they provide, and issue an Order approving these agreements. These agreements will be wholesale power agreements between two affiliated entities. FERC generally requires that agreements between affiliates be based upon a benchmark of market price, such as a market index.[97]

---

[92] *See* Harkness at 7.

[93] *See* Harkness at 8.

[94] *Id.*

[95] *Id.*

[96] *See* Harkness at 8.

[97] *See* Ficke at 9.

While transfers of energy between ULH&P and CG&E under the PSOA will occur at market prices, and the Back-up PSA, as described by Mr. Harkness, has been priced based on market indices, FERC will nevertheless scrutinize these agreements to ensure that ULH&P's customers are not harmed by these affiliate agreements.[98] This Commission's approval of these agreements will assist in demonstrating to FERC that ULH&P's customers' interests are adequately protected under these agreements.[99]

C. A Request for Proposal (RFP) would not have yielded lower-cost alternatives, and would have simply been a futile effort.

The AG presented the testimony of David H. Brown Kinloch, who advocated the AG's position that ULH&P should be required to issue an RFP for generation supply to meet its full requirements needs.[100] However, as ULH&P established in its pre-filed testimony, and again at the hearing, such an RFP process would not have yielded any credible offers of lower-cost generation supplies over the long term.[101]

As Mr. Harkness testified, ULH&P could not have obtained benefits from the marketplace similar to those it can obtain through its proposed transaction.[102] CG&E is offering ULH&P a combined package consisting of an asset transfer of existing Plants interconnected to Cinergy's joint transmission system, joint economic dispatch, and a

[98] *Id.*

[99] *Id.*

[100] *See generally* Kinloch.

[101] Note that ULH&P, given its proposal in this proceeding, has requested a waiver of the Commission's requirement in Case No. 2001-00058 that it analyze bids for purchased power in its June 2004 IRP (*see* Amendment to Application at 5). If its proposal in this proceeding is not approved, ULH&P will undertake a June 2004 filing of an IRP consistent with the Commission's Order in Case No. 2001-00058.

[102] *See* Harkness at 15.

back-up power supply arrangement, plus continuation of existing rates through 2006.[103] Other market participants might be able to offer one or another of these benefits, but the overall package is clearly unique. CG&E is offering ULH&P *existing and proven* physical assets, both coal-fired and gas-fired, that will provide ULH&P with the benefits of owning its own resources – benefits that it does not now enjoy – and will enable ULH&P to avoid the risks inherent in constructing new assets or purchasing power, and transmitting power across multiple control areas.[104] Another entity could potentially offer a generating unit for sale, but most units available for purchase in today's market are merely peaking units rather than units designed to operate as base load and/or intermediate load facilities,[105] a fact with which the AG's witness, Mr. Kinloch, would seem to concur.[106]

Even if another entity were to offer physical generation, the price at which such generation was offered would almost certainly be far greater than the price offered to ULH&P by CG&E. As supported by the testimony of Judah L. Rose, the Plants' potential market value exceeds the net book value of the Plants, even after subtracting off-system sales revenues.[107] For example, East Kentucky Power Cooperative's 268-MW Gilbert coal-fired project currently under construction is projected to cost $1,369 per kW, or

---

[103] *Id.*

[104] *Id.*

[105] *Id.*

[106] *See* Responses of the Attorney General to Interrogatories of ULH&P, Nos. 3, 5, 7.

[107] *See* Rose at 8.

$1,731 per kW in 2007 dollars.[108] Wisconsin regulators recently approved Wisconsin Energy's request to construct two new coal-fired generating units at an estimated cost of $1,884/kW (in 2007 dollars).[109] Further, the price of several coal-fired plant sales concluded since 1998 averaged $901 per kW in 2007 dollars.[110] On the other hand, CG&E is offering ULH&P an effective price of $332/kW.[111] In fact, under all of the scenarios examined by ICF Consulting, the potential market value of the Plants exceed their net book value, by as much as three times.[112] Ultimately, the Commission must recognize that there is no evidence in the record that even *suggests* that comparable generation is available at a price comparable to, much less *lower than*, that offered to ULH&P in the instant case.

Even assuming *arguendo* that a comparable mix of generating assets was available for purchase at a better price, it is highly unlikely that those would be within the Cinergy control area. Accordingly, it would be difficult if not impossible, under such a scenario, to realize the considerable benefits of minimizing the potential for transmission

---

[108] *See In the Matter of: Application Of East Kentucky Power Cooperative, Inc. For A Certificate Of Public Convenience And Necessity, And A Certificate Of Environmental Compatibility, For The Construction Of A 250 Mw Coal-Fired Generating Unit (With A Circulating Fluid Bed Boiler) At The Hugh L. Spurlock Power Station And Related Transmission Facilities, Located In Mason County, Kentucky, To Be Constructed Only In The Event That The Kentucky Pioneer Energy Power Purchase Agreement Is Terminated*, Case No. 2001-00053, 2001 Ky. PUC LEXIS 1382 (Order issued September 26, 2001). (Inflation is assumed to be 2.5% per year after 2002.)

[109] *See* Response of the Union Light, Heat and Power Company to the data requests raised at hearing, No. 1

[110] *Id.*

[111] *See* Roebel at 2 – 4 for net capacity ratings; *see* Steffen, Attachment JPS-1 for net book value of Plants as of December 31, 2006.

[112] *See* Rose at 9.

disruptions such as the August 14^{th} blackout, and of joint economic dispatch. Moreover, purchasing assets located outside of the Cinergy control area would likely result in increased transmission costs and reliability issues as compared to acquiring the Plants.[113]

As supported by the testimony of ULH&P witness Mr. Snead, a major benefit of having the Plants directly interconnected to the Cinergy joint transmission system is that it will reduce the exposure of the ULH&P system to electric supply disruptions.[114] Transactions that cross electric utility systems are generally at greater risk of curtailment simply due to exposure to more potential problems.[115] Therefore, generation imports from a greater distance can be subject to more interruptions due to transmission loading relief (TLR) procedures than power from local generation.[116] With the Plants interconnected to the Cinergy joint transmission system, reliance on power imports to the joint transmission system from other electric systems is significantly reduced.[117] Recent TLR events in the Midwest suggest that there is increasing potential for transmission constraints, with the corresponding increasing potential for disruptions of purchased power imports, including at peak times when this may be critical.[118] Utilizing generation from the Plants will help reduce ULH&P's exposure to electric supply interruptions

---

[113] *See* Harkness at 16.

[114] *See* Snead at 10. *See also* Rose at 11.

[115] *See* Snead at 10.

[116] *Id.*

[117] *Id.*

[118] *Id.*

caused by the implementation of TLR procedures due to transmission problems on other electric systems.[119] Further, ULH&P's ability to reliably purchase power from generating plants located in other areas of the electric transmission grid is uncertain.[120] For example, the Midwest ISO reports that there is zero transmission capability into Cinergy from The Louisville Gas & Electric Company (LG&E) through 2006.[121]

Without even addressing any of these transmission issues, which the AG's witnesses agree must be considered,[122] the AG advocates that ULH&P should issue an RFP that considers purchased power as an alternative to buying generating assets.[123] Setting aside for the moment the transmission issues described above, in order to approach the reliability and economic benefits of plant ownership, a purchased power arrangement would have to be long-term, *i.e.* covering a period of at least 15 years.[124] Yet in recent years, various factors have caused the market for long-term power purchases to greatly diminish.[125] These factors include the California energy crisis, the Enron debacle, bankruptcy filings by certain energy companies and the credit downgrades of other energy companies by credit ratings agencies, attempts to cancel long-term purchase power deals as a result of bankruptcy filings and litigation, the economic downturn, and

---

[119] *Id.*

[120] *Id.*

[121] Trans. Vol. I at 158.

[122] *See* Responses of the Attorney General to Interrogatories of ULH&P, Nos. 37, 83.

[123] *See* Kinloch at 14.

[124] *See* Harkness at 16.

[125] *Id.*

the continued uncertainty in the transmission market. These factors have made the long-term power market risky for buyers and as a result, new long-term purchase power agreements currently tend to run no longer than five years from the date of execution.[126] If ULH&P were to issue an RFP for its full wholesale power requirements for the long-term, the inception date for the new wholesale contract would be January 1, 2007.[127] And if the contract would run for the remaining useful life of the Plants, potential bidders would have to agree to provide a fixed price for power through an equivalent date.[128] Of course, the market for such contracts is illiquid.[129] Even if some owner of a sizeable merchant fleet would offer such an agreement against current market trends, such a solution would present risks of credit problems, bankruptcy, and efforts at contract renegotiation and, possibly, cancellation, that are now prevalent among merchants.[130] Most telling, the AG's primary witness with respect to the RFP issue is not aware of an RFP ever being issued by a utility seeking to obtain a complete set of base load, intermediate load and peaking generating assets.[131]

Thus, it is the combination of owning high quality, proven assets within and proximate to ULH&P's service area directly connected to the Cinergy transmission system, the benefits of joint economic dispatch, and the certainty of a Back-up PSA (plus

---

[126] *See* Harkness at 16.

[127] *Id.*

[128] *Id.*

[129] *Id.*

[130] *Id.*

[131] *See* Responses of the Attorney General to Interrogatories of ULH&P, Nos. 3.

the continuation of current rates through 2006 notwithstanding the asset purchase) that distinguish this package from anything else that could possibly be available in the market place, and make this package uniquely valuable to ULH&P.[132]

VI. THE RATE MAKING TREATMENT THAT ULH&P SEEKS IN THIS PROCEEDING IS JUST AND REASONABLE, AND SHOULD BE GRANTED BY THE COMMISSION AS REQUESTED.

Cinergy has conditioned its willingness to allow CG&E to transfer the Plants to ULH&P on several terms, among them receiving certain rate treatment as described in ULH&P's Amended Application and as further discussed below:

A. ULH&P's request for the Commission to fix the valuation of the Plants for ratemaking purposes is just and reasonable.

In its Amended Application, ULH&P has requested that the Commission fix the value of the Plants at their original cost less accumulated depreciation under the authority granted to the Commission by KY. REV. STAT. ANN. § 278.290.[133] ULH&P recognizes that this Commission cannot conclusively bind a future Commission; however, the authority granted to the Commission by KY. REV. STAT. ANN. § 278.290 permits the Commission to fix the value of utility assets such that these valuations can only be changed after the utility, or other party, is afforded due process:

> (1) Subject to the provisions of subsection (2) of this section, the commission may ascertain and fix the value of the whole or any part of the property of any utility in so far as the value is material to the exercise of the jurisdiction of the commission, and may make revaluations from time to time and ascertain the value of all

---

[132] *Id.*

[133] *See* Amendment to Application at 5.

> new construction, extensions and additions to the property of the utility. In fixing the value of any property under this subsection, the commission shall give due consideration to the **history and development of the utility and its property, original cost**, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for rate-making purposes.
>
> (2) The commission shall not value or revalue the property of any utility unless the valuation or revaluation is necessary or advisable in order to determine the legality or reasonableness of any rate or service or of the issuance of securities, **and then only after an investigation affecting the rate, service or securities has been instituted by the commission upon complaint or application or upon its own motion, and a hearing has been held on reasonable notice.**[134]

Significantly, KY. REV. STAT. ANN. § 278.290 contemplates a review of the history and development of the utility and the property, and specifically permits valuing property at original cost. Section (2) of this statute provides parties with due process certainty that the valuation of utility property will not be changed through any arbitrary or capricious process. By replacing its condition that ULH&P be permitted to transfer the Plants back to CG&E with this condition, that the Commission fix the value of the Plants in this proceeding, Cinergy is relying on the Commission exercising its statutory authority and the due process afforded by KY. REV. STAT. ANN. § 278.290 to provide some measure of certainty to Cinergy that ULH&P will be permitted to recover an adequate return on and of these Plants in its next base rate case.

[134] KY. REV. STAT. ANN. § 278.290 (Baldwin 2003, emphasis added)

B. The rate treatment requested for the Back-up PSA and PSOA in ULH&P's Amended Application is just and reasonable. Further, the Commission should approve these agreements.

ULH&P has requested that the Commission allow ULH&P to recover the costs associated with the Back-up PSA and PSOA. Specifically, ULH&P requested that the Commission allow the demand charges associated with the Back-up PSA, and successor back-up agreements, to be recovered in base rates.[135] ULH&P also requested that the energy charges assessed under the Back-up PSA be recoverable in its FAC in conformance with Kentucky's FAC regulation, 807 KY. ADMIN. REGS. 5:056 and applicable Commission precedent.[136] Finally, ULH&P requested that the costs associated with energy transfers under the PSOA be recoverable in its FAC in conformance with 807 KY. ADMIN. REGS. 5:056 and applicable Commission precedent.[137]

As described above, the Back-up PSA is designed to provide a firm supply of power for ULH&P's native load customers to replace the capacity of East Bend and Miami Fort 6.[138] Some outages and de-ratings of East Bend and Miami Fort 6 are inevitable, and ULH&P will need a firm supply of back-up power when this happens.[139] Where such outages are *forced outages* as defined by 807 KY. ADMIN. REGS. 5:056, ULH&P would expect to recover the energy charges as provided for in 807 KY. ADMIN.

---

[135] *See* Amendment to Application at 3.

[136] *Id.*

[137] *Id.* at 4.

[138] *See* Harkness at 3.

[139] *Id.*

REGS. 5:056. Where such outages are planned, any power taken under the Back-up PSA would be economy power (since the Back-up PSA would be jointly dispatched as a proxy for East Bend/and or Miami Fort 6[140]), and ULH&P would expect to recover these costs as economy purchases under 807 KY. ADMIN. REGS. 5:056.

The Back-up PSA allows ULH&P to obtain a firm supply of power from an affiliate that has a diverse supply of generating stations and that operates with adequate reserve margins, such that it will be able to supply the power when called upon to do so.[141] The price for the back-up power is below the price embedded in ULH&P's existing Power Sale Agreement with CG&E.[142] As demonstrated, there is considerable value in the Back-up PSA and allowing ULH&P to recover the associated costs is clearly just and reasonable.

The PSOA provides the terms and conditions under which ULH&P will allow the Plants to be jointly dispatched along with CG&E's and PSI's generating units.[143] The PSOA's energy transfer provisions specify a methodology for ensuring that transfers of energy shall be at the market price for the hour in which the energy transfer takes place, but in no event shall the price of such energy transfers exceed the incremental cost of the next available generating unit of the receiving company. As such, energy transfers under

---

[140] *See* Harkness at 11 – 12.

[141] *See* Harkness at 3.

[142] *Id. at 5.*

[143] *Id.* at 7.

the PSOA fit squarely into the definition of economy purchases recoverable under 807 KY. ADMIN. REGS. 5:056.

Significantly, the AG, through the testimony of its witness, Mr. King, endorsed ULH&P's request to recover the costs associated with these wholesale power agreements as described herein.[144]

C. ULH&P's request to defer for future recovery the transaction costs incurred by ULH&P and by CG&E on ULH&P's behalf is just and reasonable and should be approved by the Commission.

In its Amended Application and supporting testimony, ULH&P requested that a portion of the transaction costs incurred by itself and CG&E on ULH&P's behalf associated with ULH&P's acquisition of the Plants be deferred for future recovery, amortized over a five-year period.[145] ULH&P described the transaction costs it anticipated as including consulting fees, engineering assessment fees, costs associated with financing, and increases in tax liabilities, and estimated these total costs to be approximately \$4.9 million.[146] ULH&P requested authority to defer no more than \$2.45 million of these costs for future recovery.[147] As supported by the testimony of ULH&P witness Mr. Steffen, these costs represent one-time costs incurred in order to complete the proposed transaction.[148] Considering the significant value accruing to ULH&P's

---

[144] *See* King at 4 (ULH&P recognizes that Mr. King has actually endorsed ULH&P's original request for blanket approval to recover these costs.)

[145] *See* Amendment to Application at 2.

[146] *See* Steffen at Attachment JPS-7.

[147] *See* Amendment to Application at 3.

[148] *See* Steffen at 11.

customers from this transaction, as described herein and in ULH&P's Amended Application and supporting testimony, it is manifestly just and reasonable to afford ULH&P the ability to recover some portion of costs incurred to provide ULH&P's customers the benefits of this transaction.

D. *ULH&P's request to retain some portion of off-system sales is just and reasonable, and should be approved by the Commission.*

In its Amended Application, ULH&P requested Commission approval to share the profits from off-system sales as follows:

> ii. Customers shall receive up to one million dollars in profits from off-system sales annually, and 50% of such profits above one million dollars annually, if any;
>
> iii. ULH&P shall retain 50% of the profits from off-system sales above one million dollars annually, if any;
>
> iv. The costs attributable to such off-system sales shall include only the Incremental Costs listed in the PSOA, paragraph 1.10, Attachment RCM-2 to the Direct Testimony of Robert C. McCarthy previously filed in this proceeding;
>
> v. ULH&P commits to implement the processes necessary to appropriately allocate such Incremental Costs to off-system sales.[149]

Off-system sales occur when the owner of a generating facility sells power to the marketplace, after fulfilling the owner's native load and wholesale contract obligations, because the market price for power exceeds the owner's cost of generating the power.[150]

---

[149] *See* Amendment to Application at 4, 5.

[150] *See* Harkness at 11.

ULH&P currently has no off-system sales because it does not own generating facilities.[151] CG&E currently makes off-system sales under the JGDA, consisting of energy transfers to PSI, and sales to third parties.[152] Because CG&E's generation is non-regulated, CG&E retains 100% of the revenue from off-system sales from its generating stations.[153] ULH&P's off-system sales would occur under the PSOA, and would only go to CG&E.[154] CG&E would make off-system sales under both the PSOA and the JGDA.[155] Thus, any sales of ULH&P-generated energy to third parties would be made by CG&E, essentially on ULH&P's behalf.[156] If ULH&P has excess energy on an hourly basis that could be economically dispatched and sold into the market, it would be sold to CG&E as an energy transfer under the PSOA, and CG&E would either use this energy itself, or sell it into the market.[157] ULH&P would be compensated for this energy at the market price.[158]

ULH&P's original Application sought to retain all profits from off-system sales.[159] ULH&P believes that this request is appropriate because of the significant value that ULH&P's customers are realizing in acquiring "iron in the ground" at a net book value

---

[151] *Id.*

[152] *Id.*

[153] *Id.*

[154] *Id.*

[155] *Id.*

[156] *Id.*

[157] *Id.*

[158] *Id.*

[159] *See* Turner at 18.

that is less than potential market value.[160] Nevertheless, ULH&P amended its request so as to share a significant portion of the profits from off-system sales with its customers.

There is precedent in Kentucky for the sharing of off-system sales profits. The Commission has recognized the value in providing Kentucky electric utilities an incentive to engage in profitable off-system sales.[161] The AG concurs with this principle, but argues that ULH&P should only retain 10% of the profits from off-system sales.[162] The AG's witness, however, has neither performed nor reviewed any studies that would support a conclusion that this 10% retention would provide an electric utility *sufficient* incentive to maximize the value of its plants.[163] However, on cross-examination, Mr. King admitted that under ULH&P's amended proposal for sharing off-system sales, ULH&P's share of

---

[160] *Id.*

[161] *See In the Matter of: Joint Application Of Kentucky Power Company D/B/A American Electric Power, American Electric Power Company, Inc. And Central And South West Corporation For (1) Approval Of The Changes To The System Sales Clause Tariff; (2) Entry Of Certain Findings Pursuant To 15 U.S.C. 97z; (3) Entry Of Certain Findings Pursuant To 17 C.F.R. 200.53; (4) The Entry Of An Order Declaring That The Transfer Of The Stock Of Kentucky Power Company From American Electric Power Company, Inc. To Its Wholly Owned Subsidiary, Central And South West Corporation May Be Consummated Without Approval By The Commission; Or, Alternatively, Approving The Transfer Pursuant To KRS 278.020(4) And KRS 278.020(5); And (5) For Related Relief,* Case No. 2002-00039, 2002 Ky. PUC LEXIS 958, (Order issued December 17, 2002 ("Historically, Kentucky Power has had a relatively high level of revenue from off-system sales, although that revenue level has been variable. To ensure that ratepayers receive benefits from those sales, while also providing incentive for Kentucky Power to maximize those sales, a System Sales Clause has been in effect for over a decade. Under the System Sales Clause, for each month that the off-system sales net revenue exceeds a base amount, 50 percent of the excess is credited to ratepayers. Similarly, if the monthly off-system sales net revenue falls below the base amount, 50 percent of the shortfall is charged to ratepayers.")

[162] *See* King at 14.

[163] *See* Trans. Vol. II at 31.

the profits from off-system sales would approach his recommended 10% level over time given Mr. Rose's projected level of off-system sales.[164]

Given the uncontroverted agreement that electric utilities should be provided a share of the profits from off-system sales as an incentive to maximize the value of their generating resources, and the significant value being provided to ULH&P's customers in the proposed transaction, there is an abundance of evidence in the record to support ULH&P's proposal to share off-system sales as just and reasonable, and it represents a fair compromise between the original proposal offered by ULH&P and the proposal from the AG. The Commission should approve this request, and further find that it sees no reason that such treatment should not be granted in ULH&P's subsequent base rate cases.

E. ULH&P's requested treatment of ADIT and ADITC balances is in accordance with IRS rulings, is just and reasonable, and should be approved as requested.

As described by ULH&P witness Mr. Steffen, there are accumulated deferred investment tax credit (ADITC) balances and accumulated deferred income tax (ADIT) balances associated with the Plants on CG&E's books.[165] ULH&P has proposed to amortize any transferred ADIT balances on ULH&P's books *below-the-line* over the remaining lives of the Plants, and to amortize any transferred ADITC balance *below-the-line* in accordance with its current amortization schedule.[166] Amortization of these

[164] *See* Trans. Vol. II at 33.

[165] *See* Steffen at 12 – 13.

[166] *Id.* (ULH&P shall use the term *below-the-line* to indicate that the item is not to be considered for rate-making purposes, and the term *above-the-line* to indicate that the item is to be considered for rate-making purposes.)

balances *below-the-line* will exclude these pre-transfer amounts from retail ratemaking in Kentucky.[167]

The AG advocates recording these balances *above-the-line* for ratemaking purposes, thus providing ULH&P's Kentucky customers the benefit of these deferrals.[168]

ULH&P asserts that its proposed treatment is correct for several reasons. First, a thorough review of IRS precedent shows that ULH&P's position with respect to ADIT and ADITC represents the proper treatment for these items in a transaction involving a step-up in the tax basis.[169]

Second, the ADIT and ADITC balances within these accounts accrued prior to ULH&P acquiring the Plants – indeed under two regulatory schemes that are no longer in effect. That is, a portion of these balances were paid for by CG&E retail customers prior to the Plants being deregulated by Ohio's electric restructuring legislation.[170] In CG&E's stipulated settlement of its electric transition plan case, which was approved by the Public Utilities Commission of Ohio in an Order dated August 31, 2000 in Case No. 99-1658-EL-ETP, these balances were among the issues settled by the signatory parties in determining CG&E's regulatory transition charge.[171]

---

[167] *Id.*

[168] *See generally* Majoros

[169] *See* Responses of The Union Light, Heat and Power Company to data requests raised at hearing, No. 4.

[170] *See* Trans. Vol. I at 207, 216.

[171] *Id.*

Similarly, a small portion of these balances was paid for by wholesale customers, including ULH&P, prior to termination of their cost-of-service based contracts.[172] In accordance with FERC's Order 888, at the time of such termination, these wholesale customers had the ability to raise the issue of stranded benefits at FERC.[173] Since neither the Commission nor the AG raised this issue in Case No. 2001-00058, in which the current market-based PPA replacing the cost-of-service agreement was approved, nor at FERC in the subsequent federal docket, it is clear that, as in Ohio, the issue of stranded benefits was settled in these cases.

Significantly, the AG's witness, Mr. Majoros, failed to consider CG&E's electric restructuring case, Case No. 2001-00058, and FERC Order 888 in concluding that these balances should inure to the benefit of Kentucky ratepayers.[174] Nor did Mr. Majoros consider the tax normalization rules of the Internal Revenue Service.[175] Mr. Majoros did not consider that CG&E had already returned the value of these balances to ratepayers in the context of these other two cases, but in essence simply asserted that since *some*

---

[172] *See* Trans. Vol. I at 200.

[173] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket* Nos. RM95-8-000 and RM94-7-001; Order No. 888, 61 Fed. Reg. ¶ 21,540 at ¶ 21,542. ("With regard to stranded costs, the Final Rule adopts the Commission's supplemental proposal. It will permit utilities to seek extra-contractual recovery of stranded costs associated with a limited set of existing (executed on or before July 11, 1994) wholesale requirements contracts...") See *also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket* Nos. RM95-8-000 and RM94-7-001; Order No. 888B, 81 F.E.R.C. ¶ 61,248 at ¶ 62,110 ("Notwithstanding TDU Systems' arguments, we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis.")

[174] *See* Trans. Vol. II at 40 – 43.

[175] *See* Trans. Vol. II at 43, 46.

ratepayer *somewhere* had paid into these balances, ULH&P customers should now be entitled to receive the benefit.[176] While ULH&P is attempting in this proceeding to provide significant benefits to its customers,[177] it simply cannot risk the consequences of improper tax normalization treatment in doing so.[178] Thus, CG&E's willingness to transfer the Plants to ULH&P is conditioned on ULH&P recording the ADIT and ADITC amortization *below-the-line*.

Mr. Majoros also responded to a data request posed at the hearing in which he attempted to calculate an estimate of the revenue requirement impact of ULH&P's proposal to treat ADITC and ADIT *below-the-line*.[179] However, Mr. Majoros made several critical errors in this calculation, resulting in a significant overstatement of the revenue requirement impact of ULH&P's proposal. First, he used balances from March 31, 2003 rather than the estimated balances at the time of ULH&P's next projected rate case. Second, he used an incorrect "expansion factor"[180] for converting the ADITC to a revenue requirement level. Third, he used the ADITC balance as a rate base reduction, which is prohibited due to the Company's election of Section 46(f)(2) treatment of its ADITC under the Internal Revenue Code. Finally, Mr. Majoros did not take into account the fact that ADIT will only exist on ULH&P's books to the extent that the tax basis of

---

[176] *See* Trans. Vol. II at 51 – 52.

[177] *See* Trans. Vol. I at 16.

[178] *See* Trans. Vol. I at 222 – 223.

[179] *See* Attorney General's Response to Hearing Data Request.

[180] Mr. Majoros uses the term 'expansion factor' to describe what is commonly referred to as the 'revenue conversion factor'.

the assets is not stepped-up in this transaction. ULH&P believes the actual revenue requirement impact of *below-the-line* treatment of the ADIT and ADITC is significantly overstated by Mr. Majoros in his response to the Hearing Data Request.

VII. THE EVIDENCE SUPPORTS ULH&P'S REQUESTED WAIVER OF REQUIREMENTS FOR ARM'S LENGTH DEALINGS WITH ITS AFFILIATES

In its Amended Application, ULH&P requested a waiver of Kentucky's affiliate transaction pricing requirements in two areas. First, ULH&P requested a waiver of the requirements for arm's length dealing for the acquisition of the Plants from CG&E. Second, ULH&P requested a deviation from these requirements for certain fuel supply and management agreements. Each such request should be granted for the reasons set forth below.

A. ULH&P's acquisition of the Plants at net book value rather than at an arm's length market price is reasonable.

In its Amended Application, ULH&P requested a waiver of the requirement embodied in KY. REV. STAT. ANN. § 278.2213(6) that all dealings with affiliates be at arm's length.[181] As a preliminary matter, ULH&P notes the apparent incongruity of this requirement with that imposed by KY. REV. STAT. ANN. § 278.2207, which requires sales to a utility by its affiliates to be priced at the lesser of cost or market.[182] In any event,

---

[181] KY. REV. STAT. ANN. § 278.2213(6).

[182] KY. REV. STAT. ANN. § 278.2207. (It would seem obvious that in an arm's length transaction between two unaffiliated entities, agreeing on the price to be paid for a particular good or service, would result in a market price, and that the seller would usually not engage in such a transaction if the market price were to be less than its cost. Therefore, a sale at the lower of cost or market is inconsistent with an arm's length transaction. Thus, a utility complying with KY. REV. STAT. ANN. § 278.2207 arguably could be found to be in violation of KY. REV. STAT. ANN. § 278.2213(6)).

ULH&P has proposed acquiring the Plants at the lesser of cost or market, in accordance with KY. REV. STAT. ANN. § 278.2207, as supported by the testimony of Mr. Rose,[183] and there would plainly be no benefit to ULH&P's customers in requiring that they pay a higher, market-based price. It is uncontested that ULH&P is being offered the Plants at a value far less than the potential market value of the Plants. Given this great value offered to ULH&P, and by extension to its customers, as supported throughout ULH&P's filing and this Brief, it would be unreasonable to expect ULH&P to pay CG&E the higher market value of the Plants, which would have to occur for the transaction to be at arm's length in accordance with KY. REV. STAT. ANN. § 278.2213.

B. ULH&P's request for a deviation from the affiliate transaction pricing requirements related to the fuel supply, management and storage agreements is reasonable and should be approved.

ULH&P has requested a deviation from the affiliate transaction pricing requirements embodied in KY. REV. STAT. ANN. § 278.2207 and KY. REV. STAT. ANN. § 278.2213(6) for two fuel supply and management agreements and a propane storage agreement.[184] CG&E has a contract with Cinergy Marketing & Trading, LP (CM&T), its affiliate, that provides for CG&E to obtain natural gas for Woodsdale (Gas Supply and Management Agreement).[185] Additionally, CG&E has a contract with Ohio River Valley Propane LLC (ORVP), its affiliate, to store propane in the Todhunter propane cavern,

---

[183] *See* Rose at 8.

[184] *See* Amendment to Application at 7.

[185] *See* Roebel at 5.

which is partially owned by ORVP (Commodity Storage Agreement).[186] Finally, CG&E has a contract with ORVP that provides for CG&E to obtain propane for Woodsdale (Propane Supply and Management Agreement).[187]

Under the Gas Supply and Management Agreement, CM&T supplies the full requirements of natural gas needed by Woodsdale either by selling the gas to CG&E from supplies owned or controlled by CM&T or by purchasing gas from third parties as agent for CG&E.[188] CG&E pays CM&T market prices for any gas it purchases from CM&T, and reimburses CM&T for CM&T's cost to transport the gas from the point where CM&T acquires the gas to Woodsdale.[189] The Gas Supply and Management Agreement provides for CG&E to pay CM&T an administrative fee of $.03/MMBTU for gas consumed at the Plant.[190] The Gas Supply Management Agreement allows CG&E to obtain the natural gas for Woodsdale more economically by using CM&T as the supplier, versus obtaining its own supply and paying for transportation service at CG&E's tariffed rate.[191] To the extent that CG&E did not seek bids for this service, ULH&P assumes that could be characterized as not an arm's length agreement.

---

[186] *Id.*

[187] *Id.* at 6.

[188] *Id.*

[189] *Id.*

[190] *Id.*

[191] *Id.*

Under the Commodity Storage Agreement: (1) ORVP provides CG&E with 50,000 barrels of storage space within ORVP's share of the Todhunter propane cavern located in Butler County, Ohio, during the months of November through March; and (2) CG&E pays ORVP to store the propane: (a) $15,000 per month from November through March; and (b) $0.12 per barrel per month from April through October.[192] The Commodity Storage Agreement expires on November 1, 2007.[193] To the extent that CG&E did not seek bids for this service, ULH&P assumes it could be characterized as not an arm's length agreement.

The Propane Supply Management Agreement is similar to the Gas Supply Management Agreement.[194] The Propane Supply Management Agreement provides for CM&T to supply the full requirements of propane needed by Woodsdale, either from CM&T's own supplies or from supplies purchased by CM&T from third parties.[195] CG&E pays CM&T market prices for any propane it purchases from CM&T, and reimburses CM&T for CM&T's cost to transport the propane from the point where CM&T acquires the propane to Woodsdale.[196] The Propane Supply and Management

---

[192] *Id* at 7.

[193] *Id.*

[194] *Id.*

[195] *Id.*

[196] *Id.*

Agreement provides for CG&E to pay CM&T an administrative fee of $.03/MMBTU for propane consumed at the Plant.[197] The initial term of the agreement is three years.[198]

The purpose of the Propane Supply Management Agreement and the Commodity Storage Agreement is to provide propane fuel for Woodsdale as a hedge against high natural gas prices when gas is needed by Woodsdale.[199] A peaking station such as Woodsdale is designed to operate when a utility's load requirements exceed the output of its base load and intermediate load units.[200] This generally occurs during hot weather, which leads to higher demand and higher power market prices throughout the region.[201] If natural gas prices spike when Woodsdale is required to run and propane were unavailable as a substitute fuel, CG&E would lose a substantial benefit of owning peaking capacity because fuel is the largest component of Woodsdale's variable operating costs.[202] To the extent that CG&E did not seek bids for this service, ULH&P assumes that it could be characterized as not an arm's length agreement.

However, notwithstanding that these three agreements were not the result of a competitive bidding process, and thus may not be at arm's length, ULH&P requests that the Commission grant a deviation request such that ULH&P can be assigned these

---

[197] *Id* at 7 – 8.

[198] *Id* at 8

[199] *Id.*

[200] *Id.*

[201] *Id.*

[202] *Id.*

agreements. Attempting to undertake a competitive bidding process for these services, while at the same time attempting to close this transaction, would place an undue burden on ULH&P with no guarantee of any benefit arising from such a process, and would thus be unreasonable under KY. REV. STAT. ANN. § 278.2213(6). Given the benefits arising under these agreements, as described *supra,* ULH&P has demonstrated that it is in the public interest for its requested deviation to be granted.

VIII. CONCLUSION

CG&E has presented its affiliate, ULH&P, a unique opportunity to assemble a complete portfolio of high-quality, reliable electric generating plants at a price that is substantially below market and more than $600 million below the next least cost supply alternative. With the acquisition of the Plants in accordance with ULH&P's Amended Application, ULH&P's customers will see little resulting impact to their rates while enjoying the insulation from the volatility of the wholesale power marketplace that comes with generation asset ownership.[203] In return for making the Plants available to ULH&P at a price far below the potential market value of these Plants, CG&E has asked that the Commission commit to certain rate-making treatment. The treatment requested would be reasonable in any utility rate case, but is even more so here, where such significant value is being provided to ULH&P and its customers. ULH&P strongly encourages the Commission to approve each and every request made in its Amended Application so that ULH&P's customers can realize the great benefits awaiting them with the closing of this

---

[203] *See* Steffen at 4; Trans. Vol. I at 186.

proposed transaction, and enjoy a stable, reliable, low-cost supply of power for many years to come.

Respectfully submitted,

THE UNION LIGHT, HEAT AND POWER COMPANY

Michael J. Pahutski, Trial Attorney
John J. Finnigan, Senior Counsel
The Union Light, Heat and Power Company
139 East Fourth Street, 25th Floor Atrium II
Cincinnati, Ohio 45201
(513) 287-3075
Fax: (513) 287-3810

CERTIFICATE OF SERVICE

I hereby give notice that on this 18th day of November, 2003, I have mailed for filing an original and 10 true copies of the foregoing Brief with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601, and I further certify that this same day I have served the parties by mailing a true copy of the same via overnight mail, postage prepaid, to those listed below.

Michael J. Pahutski

Michael J. Pahutski

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40601

(R) 66

SUMMARY OF
THE COMMISSION'S OPINION AND ORDER OF AUGUST 31, 2000
IN THE CINCINNATI GAS & ELECTRIC COMPANY
ELECTRIC TRANSITION PLAN CASE
CASE NO. 99-1658-EL-ETP ET AL.

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (SB3) on July 6, 1999 and most provisions of SB3 became effective on October 5, 1999. Section 4928.31, Revised Code, required each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in the state of Ohio.

On December 28, 1999, Cincinnati Gas & Electric Company filed its transition plan, as well as applications for tariff approval and accounting authority. On May 8, 2000, a stipulation and recommendation on CG&E's transition plan (CG&E Ex. 60) was filed on behalf of CG&E, the staff, Ohio Consumers' Council, Ohio Council of Retail Merchants, Industrial Energy Users-Ohio, Kroger Company, The Ohio Manufacturers' Association, National Energy Marketers Association, New Energy Midwest, LLC, WPS Energy Services, Inc., Enron Energy Services, Inc., Dynegy, Inc, Cincinnati/Hamilton County Community Action Agency, Supporting Council of Preventive Effort, The Ohio Hospital Association, People Working Cooperatively, Exelon Energy, Strategic Energy, Columbia Energy Services Corp., Columbia Energy Power Marketing Corp., Mid-Atlantic Power Supply, city of Cleveland, and American Municipal Power-Ohio. Stand Energy Corp., and Local Union 1347 International Brotherhood of Electrical Workers, AFL-CIO subsequently signed the stipulation. Also on May 8, 2000, a stipulation on CG&E's employee assistance plan was filed on behalf of CG&E, the staff, Industrial Energy Users-Ohio, The Ohio Council of Retail Merchants, AK Steel, Kroger Company, The Ohio Manufacturers' Association, The Ohio Hospital Association, Columbia Energy Services Corp., Columbia Energy Power Marketing Corp., Exelon Energy, Strategic Energy, Mid-Atlantic Power Supply Assoc., Ohio Consumers' Council, New Energy Midwest, LLC, WPS Energy Services, Inc., and Enron Energy Services, Inc. A third stipulation on CG&E's independent transmission plan was filed on May 8, 2000, on behalf of CG&E, staff, Ohio Consumers' Council, The Ohio Council of Retail Merchants, Industrial Energy Users-Ohio, Kroger Company, The Ohio Manufacturers' Association, New Energy Midwest LLC, WPS Energy Services, Inc., Enron Energy Services, Inc., Dynegy, Inc., and The Ohio Hospital Association. The evidentiary hearings were held on May 30, and June 1, 2, 5, 6, 8, and 14, 2000. A local public hearing was held on June 8, 2000, in Cincinnati, Ohio.

In the opinion and order, the Commission is approving the agreements submitted by the various parties listed above with certain modification regarding the operational support plan. The Commission found that the terms of the agreements, considered in their totality, advance the public interest and provide substantial benefits to all customer classes. The stipulations provide for extended rate freezes, rate reductions, flexibility for larger contract customers not otherwise available, low income energy efficiency grants and, as a result of shorter, defined transition periods for CG&E, significant risks with respect to its ability to recover transition costs. The stipulations, among other things: provide a five-percent reduction of CG&E's generation component for residential rate schedules; waive the switching fee for the first 20 percent of residential customers that switch to a certified supplier during the market development period; create shopping credits that facilitate the development of the retail marketplace; maintain for five years the market development period, including a rate cap, to the residential customers, irrespective of the number that switch; continue support for energy efficiency and weatherization services to low-income persons by maintaining certain existing contracts valued at approximately $4 million for five years; commit CG&E to work with other regions, RTO/ISO groups and transmission level customers to develop and implement specific proposals to address reciprocity and interface/seams issues; and offer to customers with contracts approved pursuant to Section 4905.31, Revised Code, who would otherwise be on the primary distribution, transmission, or lighting rate schedules, a one-time right, through December 31, 2001, to cancel any such contract without penalty, provided that the customer remains a distribution customer of CG&E.

The Commission also determined that CG&E's transition plan filing, as amended by the settlement agreements, is in compliance with the statutory requirements contained in SB3. By approving the stipulations, the Commission also authorizes certain accounting treatments for CG&E to create the necessary regulatory assets, defer costs, and recover those costs through a regulatory transition charge.

This summary was prepared to provide a brief statement of the Commission's action in this case. It is not part of the Commission's decision and does not supersede the full text of the Commission's opinion and order.

TABLE OF CONTENTS

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The	)	
Cincinnati Gas & Electric Company for	)	Case No. 99-1658-EL-ETP
Approval of its Electric Transition Plan,	)	Case No. 99-1659-EL-ATA
Approval of Tariff Changes and New	)	Case No. 99-1660-EL-ATA
Tariffs, Authority to Modify Current	)	Case No. 99-1661-EL-AAM
Accounting Procedures, and Approval to	)	Case No. 99-1662-EL-AAM
Transfer its Generating Assets to an	)	Case No. 99-1663-EL-UNC
Exempt Wholesale Generator.	)	

OPINION AND ORDER

The Commission, coming now to consider the stipulations, testimony, and other evidence presented in these proceedings, hereby issues its opinion and order.

APPEARANCES:

James B. Gainer, Paul A. Colbert, John J. Finnigan, Jr., and Michael J. Pahutski, 139 East Fourth Street, Room 25 ATII, Cincinnati, Ohio 45202, and Baker & Hostetler, by Michael D. Dortch and Brian T. Johnson, 65 East State Street, Suite 2100, Columbus, Ohio 43215, on behalf of Cincinnati Gas & Electric Company.

Betty D. Montgomery, Attorney General of the State of Ohio, Duane W. Luckey, Section Chief, by Thomas W. McNamee and Stephen Nourse, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215-3793, on behalf of the staff of the Public Utilities Commission of Ohio.

Boehm, Kurtz & Lowry, by Michael J. Kurtz, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Chester, Willcox & Saxby, by Jeffrey L. Small, 17th South High Street, Suite 900, Columbus, Ohio 43215, on behalf Ohio Council of Retail Merchants, and by John W. Bentine, on behalf of the city of Cleveland and The American Municipal Power-Ohio, Inc.

McNees, Wallace & Nurick, by Samuel C. Randazzo, Gretchen J. Hummel, and Kimberly J. Wile, Fifth Third Center, 21 East State St., Suite 1799, Columbus, Ohio 43215, on behalf of The Industrial Energy Users-Ohio.

Boehm, Kurtz & Lowry, by David F. Boehm, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of AK Steel Corporation.

David C. Rinebolt, PO Box 1793, Findlay, Ohio 45839-1793, on behalf of Ohio Partners for Affordable Energy.

Sutherland, Asbill & Brennan LLP, by Paul F. Forshay and Keith McCrea, 1275 Pennsylvania Avenue, NW, Washington, DC 20004-2415, on behalf of Shell Energy Services Co., LLC.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker-Bartemes, 100 South Third Street, Columbus, Ohio 43215-2368, on behalf of The Ohio Manufacturers' Association, Strategic Energy LLC, Columbia Energy Services Corp., Columbia Energy Power Marketing Corp., Exelon Energy, and MidAtlantic Power Supply Association, and by Wanda M. Schiller on behalf of Strategic Energy LLC, and by David Dulick on behalf of Exelon Energy.

Robert S. Tongren, Ohio Consumers' Counsel, by Evelyn R. Robinson-McGriff and Werner L. Margard, III, Assistant Consumers' Counsels, 10 W. Broad St., Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential consumers of The Cincinnati Gas & Electric Company.

Craig Goodman, 3333 K Street, N.W., Suite 425, Washington, D.C. 20007 and John & Hengerer, by Joelle Ogg, 1200 17th Street, NW, Suite 600, Washington, D.C. 20036, on behalf of the National Energy Marketers Association.

Thompson, Hine and Flory, by Robert P. Mone and Scott A. Campbell, 10 West Broad Street, Suite 700, Columbus, Ohio 43215, on behalf of the Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, PO Box 1008, Columbus, Ohio 43216-1008, on behalf of Enron Energy Services, Inc.; New Energy Midwest, LLC; WPS Energy Services, Inc.; and Dynegy, Inc., and Janine L. Migden, 400 Metro Place North, Suite 310, Dublin, Ohio 43017-3375, on behalf of Enron Energy Services, Inc.

Judith A. Phillips, 1077 Celestial Street, Suite 110, Cincinnati, Ohio 45202, on behalf of Stand Energy Corporation.

Ellis Jacobs, 333 W. First Street, Suite 500, Dayton Ohio 45402, on behalf of the Supporting Council of Preventive Effort and Cincinnati/Hamilton County Community Action Agency.

Bell, Royer & Sanders Co., LPA, by Langdon D. Bell, 33 South Grant Avenue, Columbus, Ohio 43215-3927, on behalf of the Greater Cleveland Growth Association.

Snyder, Rakay & Spicer, by Gary A. Snyder, 316 Talbot Tower, Dayton, Ohio 45402, on behalf of Local Union 1347, International Brotherhood of Electrical Workers, AFL-CIO.

Richard L. Sites, 155 East Broad Street, Columbus, Ohio 43215-3620, on behalf of The Association for Hospitals and Health Systems, dba Ohio Hospital Association.

Bruce Weston, 169 West Hubbard Avenue, Columbus, Ohio 43215, on behalf of People Working Cooperatively.

William M. Ondrey Gruber, 2714 Leighton Road, Shaker Heights, Ohio 44120, and Vicki L. Deisner, 1207 Grandview Avenue, Room 201, Columbus, Ohio 43212-3449, on behalf of the Ohio Environmental Council.

Jodi M. Elsass-Locker, Assistant Attorney General, 77 South High Street, 29th Floor, Columbus, Ohio 43215 and Maureen Grady, 369 South Roosevelt Avenue, Columbus, Ohio 43209, on behalf of the Ohio Department of Development.

I. HISTORY OF THE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bell No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (hereinafter SB3) on July 6, 1999, and most provisions of SB3 became effective on October 5, 1999. Section 4928.31, Revised Code, requires each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in Ohio. The plan must include a rate unbundling plan, a corporate separation plan, a plan to address operational support systems and any other technical implementation issues related to competitive retail electric service, an employee assistance plan, and a consumer education plan. On December 28, 1999, Cincinnati Gas & Electric Company (CG&E or the Company) filed its transition plan, appendices, schedules, testimony, and supplemental information, pursuant to SB3. On January 7, 2000, CG&E held a technical conference with interested parties on its consumer education plan and employee assistance plan.[1] Between January 26, 2000, and February 14, 2000, various parties filed objections to CG&E's transition plan filings. By entry of February 1, 2000, an additional technical conference was held on February 24, 2000. By entry of March 2, 2000, a second prehearing conference was scheduled for May 11, 2000, and the hearing was scheduled for May 22, 2000. At the request of the parties, the hearing was continued to May 30, 2000. Supplemental testimony was filed by CG&E on May 1 and 3, 2000. CG&E filed a second supplemental testimony of its witnesses on May 17, 2000. AK Steel Corporation (AK Steel), Buckeye Power, Inc. (Buckeye), and Ohio Rural Electric Cooperatives (OREC) filed testimony on May 24, 2000. Pursuant to Section 4928.32(B), Revised Code,

---

1 Also on January 21 and 25, 2000, CG&E held technical conferences on its operational support plan and rate unbundling plan. Between February 3 and 14, 2000, CG&E held technical conferences on the transition revenue, corporate separation, independent transmission, and shopping incentive portions of its transition plan.

the Staff Report of Exceptions and Recommendations (Staff Report) was filed on March 28, 2000.

Intervention was granted in this proceeding to the following parties: Kroger Company; The Ohio Council of Retail Merchants; Industrial Energy Users-Ohio; AK Steel; Ohio Partners for Affordable Energy; Shell Energy Services Company, LLC (Shell); The Ohio Manufacturers' Association; Ohio Consumers' Council; National Energy Marketers Association; OREC; Buckeye Power, Inc.; New Energy Midwest, LLC; WPS Energy Services, Inc., Dynegy, Inc.; Enron Energy Services, Inc.; Stand Energy Corporation; PP&L Energy Plus Co.; Exelon Energy; Strategic Energy; Columbia Energy Services Corp.; Columbia Energy Power Marketing Corp.; Mid-Atlantic Power Supply Association; The Cincinnati/Hamilton County Community Action Agency; The Supporting Council of Preventive Effort; Local Union 1347, International Brotherhood of Electrical Workers, AFL-CIO; The Association for Hospitals and Health Systems, d.b.a. The Ohio Hospital Association; American Municipal Power-Ohio, Inc.; People Working Cooperatively; Ohio Environmental Council, Ohio Department of Development (ODOD); and Greater Cleveland Growth Association.[2]

On May 8, 2000, a stipulation and recommendation on CG&E's transition plan (CG&E Ex. 60) was filed on behalf of CG&E; the staff, Ohio Consumers' Council; Ohio Council of Retail Merchants; Industrial Energy Users-Ohio; Kroger Company; The Ohio Manufacturers' Association; National Energy Marketers Association; New Energy Midwest, LLC; WPS Energy Services, Inc.; Enron Energy Services, Inc.; Dynegy, Inc.; Cincinnati/Hamilton County Community Action Agency; Supporting Council of Preventive Effort; The Ohio Hospital Association; People Working Cooperatively; Exelon Energy; Strategic Energy; Columbia Energy Services Corp.; Columbia Energy Power Marketing Corp.; Mid-Atlantic Power Supply; city of Cleveland; and American Municipal Power-Ohio. Stand Energy Corp. and Local Union 1347, International Brotherhood of Electrical Workers, AFL-CIO, subsequently signed the stipulation. Also on May 8, 2000, a stipulation on CG&E's employee assistance plan was filed on behalf of CG&E; the staff; Industrial Energy Users-Ohio; The Ohio Council of Retail Merchants; AK Steel, Kroger Company; The Ohio Manufacturers' Association;, The Ohio Hospital Association; Columbia Energy Services Corp.;, Columbia Energy Power Marketing Corp.; Exelon Energy; Strategic Energy; Mid-Atlantic Power Supply Assoc.; Ohio Consumers' Council; New Energy Midwest, LLC; WPS Energy Services, Inc.; and Enron Energy Services, Inc. A third stipulation on CG&E's independent transmission plan was filed on May 8, 2000, on behalf of CG&E; staff; Ohio Consumers' Council; The Ohio Council of Retail Merchants; Industrial Energy Users-Ohio; Kroger Company; The Ohio Manufacturers' Association; New Energy Midwest, LLC; WPS Energy Services, Inc.; Enron Energy Services, Inc.; Dynegy, Inc.; and The Ohio Hospital Association.

---

2 PP&L EnergyPlus Co. was granted intervention in these proceedings but filed a notice of withdrawal on March 13, 2000. The motions to intervene on behalf of FirstEnergy, Ohio Edison, Cleveland Electric Illuminating Company, and Toledo Edison were denied on March 23, 2000.

The evidentiary hearings were held on May 30, and June 1, 2, 5, 6, 8, and 14, 2000. CG&E filed its rebuttal testimony on June 12, 2000. A local public hearing was held on June 8, 2000, in Cincinnati, Ohio. Initial briefs were filed on July 5, 2000, by CG&E, staff, AK Steel, Buckeye and OREC collectively, Shell, People Working Cooperatively, Ohio Consumers' Council, and Industrial Energy Users-Ohio. Reply briefs were filed on July 19, 2000, by CG&E, Staff, Shell, AK Steel, and Buckeye and OREC.

II. SUMMARY OF THE STIPULATIONS

A. The Transition Plan Stipulation

CG&E's transition plan stipulation provides, among other things, that:

(1) CG&E agrees to eliminate the $563 million of generation transition charge (GTC) recovery proposed in its transition plan.

(2) Approval of the stipulation shall be deemed to grant to CG&E accounting authority to create the necessary regulatory assets and defer costs and recover, through a regulatory transition charge (RTC), the following regulatory assets, including but not limited to existing regulatory asset balances on CG&E's books as of December 31, 2000, deferral of transition implementation costs, deferral of purchased power costs sufficient to maintain an adequate operating reserve margin as determined by CG&E, deferral of the litigation cost reimbursement, deferral of the Ohio Excise Tax overlap, and deferral or adjustment to the amortization schedule to reflect the effects of any shopping incentive. CG&E will not seek rate recovery of any costs deferred pursuant to such accounting authority that are not recovered through the RTC. During the market development period (MDP), for accounting purposes, there exists an implied residual RTC (unbundled generation charge less the shopping credit provided to customers). All regulatory assets created and recovered pursuant to this stipulation are in compliance with the requirements of Sections 4928.39 and 4928.40, Revised Code.

(3) There will be no further netting or adjustment of any kind to CG&E's transition cost recovery, including but not limited to any adjustment of RTC rates, or shopping credits through 2010, related to the sale, lease, or transfer by CG&E, or any of its affiliate, of any generating asset.

(4) CG&E will not end the MDP for residential customers prior to December 31, 2005.

(5) CG&E may end the MDP for all customer classes, except for the residential class, when 20 percent of the load of such class switches the purchase of its generation supply to a certified supplier. This provision is effective only to the extent that CG&E does not possess as an affiliate a retail electric generation provider, selling commodity generation at retail. This paragraph also requires that CG&E measure switching by kilowatt-hour (kWh) for the residential class, and average demand for all other customers. At the end of the MDP for each non-residential rate schedule, the rate freeze on non-switching customers and the rate freeze for transmission, distribution, and ancillary service on switching customers will end. The shopping credit established at the time of exercising choice for switching customers will continue as a credit on the bills of such switching customers through December 31, 2005, and will not be affected by the end of the MDP; and the RTC will be collected from all non-residential customers pursuant to the stipulation through December 31, 2010.

(6) CG&E will make the RTC charge load factor sensitive for rate classes billed on demand/energy rates. The RTC rate design will include a declining block structure where the first kWh per kW of billing demand will recover the RTC charge to the maximum extent possible.

(7) The parties agree with and adopt CG&E's independent transmission plan stipulation and CG&E's employee assistance plan stipulation.

(8) CG&E's exempt wholesale generator (EWG) is prohibited from selling power to an affiliate for resale at retail in CG&E's service territory, except through CG&E's requirements commodity service agreement (RCSA) and is prohibited from selling to an affiliate certified supplier on more favorable prices or terms than CG&E sells to a non-affiliate certified supplier. The information regarding the sales or transfers of power and ancillary services by the EWG to an affiliate shall be simultaneously posted with the execution

of any agreement for the sale or transfer on a publicly available electronic bulletin board. These provisions do not apply during the MDP to wholesale sales of power and ancillary services from the EWG to CG&E for CG&E standard offer customers under the RCSA. Approval of the stipulations constitutes a finding of fact by the Commission of the items necessary for the Federal Energy Regulatory Commission (FERC) to approve CG&E's EWG and RCSA. Namely: that the transaction under the RCSA will benefit consumers; does not violate any state law; would not provide the EWG any unfair competitive advantage by virtue of its affiliation with CG&E; and is in the public interest. Also, with respect to the transfer of CG&E generation assets to an EWG, allowing such generation assets to be an eligible facility for EWG ownership: will benefit consumers; is in the public interest; and does not violate state law.

(9) The following rates and terms, which reflect a five-percent reduction of CG&E's generation component, including RTC, shall be approved for the customers on residential rate schedules: the shopping credit on the bills of switching customers for the first 20 percent of the load per class for the calendar years 2001-2005 will be 5.0000 cents/kWh. The shopping credit on the bills of switching customers after 20 percent of the load per class switches for the calendar years 2001-2005 will be 3.9407 cents/kWh. For the calendars years 2006-08 all residential customers will pay an RTC rider of 0.6114 cents/kWh. Residential customers will pay no RTC after December 31, 2008. The kWh associated with Percentage of Income Payment Program (PIPP) customers will not be included in the determination of the first 20 percent of the switching customers' load per class. CG&E's EWG will not bid to supply the CG&E PIPP customers if such customers are aggregated and bid out as a group.

(10) The shopping credit for secondary distribution small is established as 5.3601 cents/kWh through December 31, 2005, for the first 20 percent of load that switch, and 4.5438 cents/kWh through December 31, 2005, for the remaining 80 percent. The RTC for secondary distribution small is established as 0.9499 cents/kWh from the end of the MDP through December 31, 2010. The shopping credit for secondary distribution large is established as 4.8145 cents/kWh through December 31, 2005, for the first 20 percent that

switch, and 4.2460 cents/kWh through December 31, 2005, for the remaining 80 percent. The RTC for secondary distribution large is established as 0.6719 cents/kWh from the end of the MDP through December 31, 2010. Secondary distribution small and secondary distribution large customers also have an identifiable shopping credit and RTC through December 31, 2010.

(11) The shopping credit for primary distribution is established as 3.8877 cents/kWh through December 31, 2005, for the first 20 percent that switch, and 3.5145 cents/kWh through December 31, 2005, for the remaining 80 percent. The RTC for primary distribution is established as 0.4562 cents/kWh from the end of the MDP through December 31, 2010. The shopping credit for transmission is established as 3.27 cents/kWh through December 31, 2005, for the first 20 percent that switch, and 3.0322 cents/kWh through December 31, 2005, for the remaining 80 percent. The RTC for transmission is established as 0.3043 cents/kWh from the end of the MDP through December 31, 2010. The shopping credit for lighting is established as 3.0057 cents/kWh through December 31, 2005, for the first 20 percent that switch, and 2.8272 cents/kWh through December 31, 2005, for the remaining 80 percent. The RTC for lighting is established as 0.2290 cents/kWh from the end of the MDP through December 31, 2010. Customers with contracts approved pursuant to Section 4905.31, Revised Code, who would otherwise be on the primary distribution, transmission, or lighting rate schedules shall have a one-time right through December 31, 2001, to cancel any such contract without penalty, provided that the customer remains a distribution customer of CG&E.

(12) CG&E will maintain certain of its existing contracts with providers of energy efficiency and weatherization contracts until December 31, 2005.

(13) The Universal Service Fund (USF) Rider and the Energy Efficiency Revolving Loan Fund Rider will be determined by the ODOD and approved by the Commission.

(14) CG&E agrees to accept any resolution of issues agreed to by all Operational Support Planning for Ohio Taskforce (OSPO) working group participants and to incorporate any such

changes in its transition plan except with respect to the following: CG&E will establish new minimum stay rules for residential customers; CG&E will amend its open access transmission tariff to add a new schedule for retail energy imbalance service; CG&E commits to use its best efforts to take the actions necessary to purchase supplier accounts receivable and to provide consolidated bill ready billing and supplier consolidated billing; and CG&E agrees to revise the collateral computation that it will use for establishing a certified supplier's creditworthiness. In addition, large commercial and industrial customers who return to CG&E's standard service offer other than through certified supplier default must provide at least 90-days advance notice to CG&E if they are planning to return to CG&E's standard service offer between May 1 and October 31 of each calendar year.

(15) CG&E will waive the switching fee for the first 20 percent of residential customers that switch the purchase of generation supply to a certified supplier during the MDP.

(16) CG&E will establish a technical task force to resolve ongoing technical issues that may arise due to restructuring implementation.

(17) CG&E will pay $1.5 million in litigation reimbursement to the active intervenor signatory parties.

(18) The parties agree that the stipulation is conditioned upon adoption in its entirety by the Commission without material modification by the Commission and, if the Commission rejects or modifies all or any part of this stipulation or imposes additional conditions or requirements upon the parties, the parties shall have the right within 30 days of issuance of the Commission's order to either file an application for rehearing or terminate and withdraw from the stipulation.

B. The Independent Transmission Plan (ITP) Stipulation

On May 8, 2000, CG&E filed its ITP stipulation. CG&E's ITP stipulation provides that:

(1) The sum of CG&E's transmission and distribution rates shall remain frozen during the MDP such that if CG&E's

unbundled transmission rate increases, its unbundled distribution rate shall decrease by the inverse amount. CG&E will also perform and file a FERC seven-factor test by March 31, 2001.

(2) Until the Midwest Independent System Operator (MISO) becomes operational, CG&E and its affiliates shall provide for transmission service for both affiliates and non-affiliates on the same terms and conditions, consistent with Open Access Same-Time Information System (OASIS) and FERC Standards of Conduct. CG&E will also provide distribution service only under the rates, terms and conditions stated in its distribution tariffs.

(3) A transmission customer receiving retail commodity service will have the same priority for requesting and receiving network transmission service as an existing network customer under CG&E's open access transmission tariffs (OATT).

(4) Retail customers or their certified suppliers who take 138 kV transmission service are entitled to receive either network or firm point-to-point transmission service or any other transmission service for which the customer is eligible.

(5) CG&E agrees to participate in the collaborative process under FERC Order 2000, 89 FERC Section 61,285, to discuss integrating the facilities of the transmission-owning utilities in Ohio so as to achieve the objectives listed in Rule 4901:1-20-17(B)(3), O.A.C., and Section 4928.12, Revised Code. To the extent not resolved in the Commission proceeding: *In the Matter of the Commission's Investigation Into the Adequacy and Availability of Electric Power for the Summer Months of 2000 from Ohio's Investor-Owned Electric Utility Companies,* Case No. 00-617-EL-COI, CG&E will enter into a joint stipulation with all of the other transmission-owning utilities in Ohio to submit the subject of how to achieve the objectives listed in Rule 4901:1 -20-17(B)(3), O.A.C., and related issues to a separate joint Commission hearing dealing solely with that subject as part of their respective transition plan application proceedings; or if such other transmission-owning utilities will not so agree, to jointly request, together with all of the other intervenors in this case, that the Commission order the other transmission-owning utilities to participate in such a hearing. CG&E will also participate in a statewide collaborative process to resolve

the transmission seams issues in Ohio to effectuate the policy objectives of Section 4928.12, Revised Code.

C. The Employee Assistance Plan (EAP) Stipulation

On May 8, 2000, CG&E filed its EAP stipulation. No parties oppose the EAP stipulation. The EAP stipulation provides that:

(1) CG&E's EAP, as originally filed in this case, be found to comply with Section 4928.31, Revised Code, and Rule 4901:1-20-03, O.A.C., Appendix C.

(2) The parties who intervened in CG&E's transition plan proceeding withdraw all of their preliminary objections relating to CG&E's EAP. Specifically, Coalition for Choice in Electricity (CCE)[3] withdraws preliminary objections Section D, including D-1 through D-3, and Industrial Energy Users-Ohio, Cincinnati/Hamilton County Community Action Agency and Supporting Council of Preventive Effort withdraw their adoption of CCE's preliminary objections Section D

(3) To the extent that the parties have representatives serving on the electric employee assistance advisory board established under Section 4928.431, Revised Code, the parties agree that their representatives will recommend to the Commission that the Commission approve CG&E's EAP.

(4) The parties agree that nothing herein resolves or waives any party's right to present evidence and arguments in these cases regarding CG&E's request to recover costs associated with employee assistance incurred under CG&E's EAP, in accordance with Section 4928.39, Revised Code.

3 CCE is composed of The Ohio Manufacturers' Association, The Industrial Energy Users-Ohio, The Ohio Council of Retail Merchants, Ohio Partners for Affordable Energy, Enron Energy Services, Inc., Supporting Council of Preventative Effort, Corporation of Ohio Appalachian Development, New Energy Midwest, LLC, Greater Cleveland Growth Assoc., Ashtabula County Community Action Agency, and WPS-Energy Services, Inc.

III. COMMISSION REVIEW OF THE STIPULATIONS, CG&E'S TRANSITION PLAN COMPLIANCE WITH SECTION 4928.34, REVISED CODE, AND ISSUES RAISED BY PARTIES OPPOSING THE STIPULATIONS.

A. CG&E's Operations Support Plan (OSP)

On November 30, 1999, the Commission issued an entry in Case No. 99-1141-EL-ORD, directing Ohio's investor-owned electric utilities and interested stakeholders to participate in a taskforce for the development of uniform business practices and electronic data interchange (EDI) standards. Pursuant to this directive, the Commission's staff created the OSPO taskforce. On May 15, 2000, numerous OSPO participants filed a *pro forma* certified supplier tariff (*pro forma* tariff) and a stipulation (OSPO stipulation) in each utility's transition plan case. The *pro forma* tariff contains a number of service regulations on which the parties were able to agree. These relate to: supplier registration and credit requirements, end-use customer enrollment process, end-use customer inquiries and requests for information, metering services and obligations, load profiling and scheduling, transmission scheduling agents, confidentiality of information, voluntary withdrawal by a competitive retail electric service (CRES) provider, liability, and alternative dispute resolution. In the OSPO stipulation, the parties specifically request the Commission to resolve issues in four general areas: (1) energy imbalance service, (2) minimum stay requirements for residential and small commercial customers returning to standard offer service, (3) consolidated billing and purchase of receivables, and (4) adoption of EDI standards. On May 18, 2000, the Commission issued an entry initiating a generic docket (Case No. 00-813-EL-EDI) to establish procedures for parties desiring to file comments and reply comments regarding the OSPO stipulation and *pro forma* tariff. On July 20, 2000, the Commission issued a finding and order approving the OSPO stipulation and resolving the four issues left unresolved.

Under the transition plan stipulation in this case, CG&E agrees to incorporate into its transition plan, the OSPO stipulation and *pro forma* tariff with exception of certain terms that the stipulating parties have agreed will apply to CG&E. These terms include: (1) the establishment of new minimum stay rules for residential customers; (2) amendments to CG&E's open access transmission tariff to add a new schedule for retail energy imbalance service; (3) using CG&E's best efforts to take the actions necessary to purchase certified supplier accounts receivable and to provide consolidated bill ready billing and supplier consolidated billing; and (4) agreeing to revise the collateral computation that it will use for establishing a certified supplier's creditworthiness. Shell contends that allowing CG&E to exempt these four areas from compliance with the OSP stipulation will undermine the entire OSP process, preclude universal practices that the Commission tried to establish through the OSP task force, and will deter the development of effective competition.

Under CG&E's minimum stay requirement, during the MDP, a residential customer who takes generation service from CG&E for any part of the period May 15 through September 15 (the stay out period) must remain a standard offer customer through May 14 of the following year before such customer may elect to switch to another supplier, provided that: (1) customers may switch suppliers at any time if they have not previously switched; (2) following the stay out period through the following May 14, returning customers may switch to another supplier at any time for the remainder of the MDP; and (3) during the first year of the MDP, residential customers returning to CG&E's standard offer service will not be subject to a minimum stay. Further, if a certified supplier defaults, an end-use customer has a one billing cycle time period in which to select another certified supplier. If the end-use customer fails to select another certified supplier by the end of one billing cycle, the end-use customer will remain on CG&E's standard service offcer and be subject to any applicable minimum stay requirement.

Shell contends that CG&E's proposed minimum stay requirement violates SB3, as it contends SB3 contemplates no limitation on a residential customer's freedom of movement between service options even if those movements involve a return to standard offer service. Shell also claims that CG&E's minimum stay provision could remove large numbers of such consumers from the competitive market place for substantial periods of time and reduce competition.

With respect to the issue of CG&E's minimum stay requirements, we defer to our ruling in our July 19, 2000 finding and order in *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the Electric Utility Industry*, Case No. 00-813-EL-EDI (hereafter 00-813). In that order, we approved the use of minimum stay requirements conditioned upon the development of a market-based "come and go" rate alternative service. See page 13 of our finding and order in 00-813. We also prohibited the imposition of a mandatory stay when a customer defaults to the utility's standard offer service due to the default of the supplier of electricity. We also established a uniform penalty free return to standard offer service policy and a uniform period throughout Ohio in which companies can impose a summer/stay period of May 16th through September 15th. Accordingly, the Commission will approve the stipulation's treatment of minimum stay requirements conditioned upon certain modification so that CG&E's minimum stay requirements are in compliance with our order in 00-813 and any entry on rehearing therefrom.[4]

Shell also objected to CG&E's retail energy imbalance service proposal, which it argues would create a narrow energy imbalance bandwidth for transmission scheduling agents. Shell contends that these bandwidths present an intolerable approach to energy imbalances for those transmission-scheduling agents trying to serve weather sensitive residential loads. Shell claims that the stipulation's energy imbalance service

---

[4] We note that on August 24, 2000, CG&E filed a request for exception in these proceedings regarding minimum stay requirements. Inasmuch as the issue raised in that request are the same issues raised in the company's application for rehearing in 00-813, the Commission will address the issues in the entry on rehearing.

proposal would achieve an anticompetitive outcome the Commission should avoid, namely, imbalances as an increasing source of penalty costs for residential marketers and an increasing revenue source for CG&E.

Under the transition plan stipulation, CG&E will amend its OATT to add a new schedule for retail energy imbalance service. In addition, CG&E will amend its OATT application procedures to allow a "description of purchased power designated as network resource including source control area location, transmission arrangements and delivery point(s) to the transmission provider's transmission system." CG&E will also amend its OATT to allow transmission customers to designate new resources on a day-ahead basis, provided that there exists available transfer capacity, that it is subject to the approval of the transmission provider, and that the transmission customer relinquishes network transmission rights to a designated resource once a new resource is designated.

On this issue, only Shell is actively opposing the CG&E transition case stipulation while the other intervening marketers signed the CG&E transition case stipulation. Further, Shell offered no evidence at hearing to support its position. We believe that CG&E's proposal for energy imbalances is reasonable. As we noted in 00-318, although a single standard for operations is a goal which we would hope to eventually achieve in Ohio, we recognize that a great many differences currently exist between the electric utilities, who have traditionally operated in isolation with their own unique computer systems and processes, and that some differences will need to be accepted by suppliers if Customer Choice is to become a reality on January 1, 2001. We also considered the fact that each utility will only need to have an energy imbalance mechanism until its transmission assets become part of a functioning RTO, at which time, the RTO would become responsible for energy imbalance service. Since CG&E is anticipated to be in an RTO by 2001, we do not believe that uniformity with all the other utilities in the interim is crucial to the development of the Ohio choice market with the changes to CG&E's OATT set forth in the stipulation. Therefore, we do not find CG&E's energy imbalance service proposal to be anticompetitive.

Shell also raised an issue related to CG&E's proposal for consolidated billing. Under the OSP, CG&E will use its best efforts in taking the actions necessary to implement purchasing of supplier accounts receivable by June 1, 2001, to implement consolidated bill ready billing by January 1, 2002, and to implement supplier consolidated billing by June 1, 2002. These provisions are based on CG&E's best efforts and do not require CG&E to take any action that would hinder or delay the implementation of the competitive framework necessary to facilitate customer choice in its service territory. Further, the implementation of these billing functions is not contingent upon the Commission making a determination under Section 4928.04, Revised Code, with respect to the unbundling of the billing function, but shall proceed independent of any supplier compensation or CG&E credit for such billing service.

Shell contends that the transition plan stipulation makes no provision for a billing credit from CG&E in the event that a customer decides to take its billing services from a third party. Shell argues that it intends to perform consolidate billing for its customers and that permitting a year lag between implementation of utility and supplier consolidated billing would place Shell at a competitive disadvantage against those marketers that rely on CG&E's billing functions. Shell also complains that the consolidated billing proposals would preclude marketers from establishing a communication link in order to build supplier name recognition and consumer loyalty.

As we determined in 00-813, we have adopted a target date for consolidate bill-ready billing by no later than June 1, 2002, and a target date for supplier consolidated billing by July 1, 2002. Having determined these dates are reasonable and the fact that CG&E's proposal agrees to dates earlier, we find the stipulated target dates by CG&E are reasonable.

Shell contends that CG&E's OSP would impose additional collateral requirements on third-party suppliers beyond those adopted in the OSP *pro forma* tariff. Shell contends that the proposed collateral calculation relies too heavily on CG&E-generated usage estimates which, in the case of new market entrants, would amount to guess work. Shell argues that it is unclear how parties could verify either the shopping credit calculations or pricing data used by CG&E to establish these additional collateral obligations. Also, Shell claims that there is no support for why such additional collateral is needed.

CG&E notes that its OSP provides for implementing a collateral calculation that will be applicable to certified suppliers who serve retail customers in CG&E's service territory and is intended to cover CG&E's risk as the default supplier. CG&E will calculate the amount of collateral to cover its risk as the default supplier by multiplying 45 days of CG&E's estimate of the summer usage of the certified supplier's customers by a price set at the highest monthly average megawatt hour price for CG&E off-system purchased power from the prior summer less the average shopping credit that CG&E will receive due to the defaulting certified supplier's customers returning to CG&E's standard service offer.

On this issue, Shell offered no evidence to support its position. On review, we find CG&E's proposal quantifiable and not, as suggested by Shell, mere guess work. We also find that a collateral calculation applicable to certified suppliers who serve retail customers in CG&E's service territory will cover CG&E's risk as the default supplier. Finally, CG&E will be expected to be able to verify its charges to any affected certified supplier or retail customer upon request.

Based on our findings above, we believe the company's operational support plan set forth in the stipulation, subject to modification to comply with 00-813, is reasonable and appropriately addresses operational support systems and technical implementation procedures. Accordingly, we find the transition plan meets the statutory requirements of Section 4928.34(A)(9), Revised Code. We also note that CG&E's transition plan filing included a proposed billing format. The Commission directs the staff to finalize a bill format which includes a "price to compare" (which is the price for an electric supplier to beat in order for the customer to save money) for residential and small commercial customers. As part of our approval of CG&E's transition plan, the company must meet staff's requirements regarding billing format.

B. CG&E's Unbundling Plan

Section 4928.31(A)(1), Revised Code, requires that the filed transition plans contain a rate unbundling plan that separates existing, bundled utility rates into their component parts consistent with the provisions of Section 4928.34(A), Revised Code, and applicable Commission rules. Discussed below are the various requirements regarding unbundling contained in Section 4928.34(A), Revised Code, CG&E's plans for unbundled rates, and AK Steel's objections.

Provisions of Section 4928.34(A), Revised Code

1. Unbundled Transmission Component (Section 4928.34(A)(1), Revised Code)

Under this section, the Commission must determine whether the unbundled components for the electric transmission component of retail electric service equal the tariff rates determined by the FERC in effect on the date of approval of the transition plan. The unbundled transmission component must include a sliding scale of charges to ensure that refunds determined or approved by the FERC are flowed through to retail electric customers.

CG&E states that all stipulating parties have agreed that CG&E's rate unbundling plan satisfies the statutory requirements of Section 4928.34(A)(1), Revised Code (CG&E Ex. 60 at 3, 5, 6). As described by CG&E witness John P. Steffen, CG&E developed its unbundled transmission and ancillary services rates from CG&E's current FERC approved OATT (CG&E Ex. 12 at 8, 16-18). CG&E's proposed unbundled transmission rates are set out in Schedules UNB-1, UNB-7.1 and UNB-7.2 (CG&E Ex. 23). Consistent with Section 4928.34(A)(1), Revised Code, and Rule 4901:1-20-03, App. A, Part (C)(2), O.A.C., these unbundled components reflect the OATT rates approved by FERC, which rates are currently in effect and are not subject to refund (CG&E Ex. 12 at 7).

Consistent with Rule 4901:1-20-03, App. A, Part (C)(2)(a), O.A.C., CG&E has unbundled and set out as separate components in its proposed tariffs, Schedules UNB-1, 7.1 and 7.2, the following ancillary services: (1) Scheduling, System Control and Dispatch, (2) Reactive Supply and Voltage Control, (3) Regulation and Frequency Control, (4) Spinning Reserve, and (5) Supplemental Reserve (CG&E Ex. 23). The rates for these services are based on the FERC rates currently in effect (CG&E Ex. 12 at 7).

2. Unbundled Distribution Component (Section 4928.34(A)(2), Revised Code)

This section requires that the unbundled components for retail electric distribution service in the rate unbundling plan equal the difference between the costs attributable to the Company's transmission and distribution rates based on the Company's most recent rate proceeding, and the tariff rates for electric transmission service determined by the FERC under division (A)(1) of this section.

CG&E states that, consistent with Section 4928.34(A)(2), Revised Code, and Rule 4901:1-20-30, App. A, Part (C)(3), O.A.C., the unbundled distribution rate component developed by CG&E is the difference between the sum of the transmission and distribution components of rates in effect on October 5, 1999, as further adjusted to reflect the effect of tax changes attributable to amendment of Section 5727.111, Revised Code, by SB3 and the unbundled transmission rate determined pursuant to Section 4928.34(A)(1), Revised Code (CG&E Ex. 12 at 7). CG&E functionalized costs to generation, distribution, transmission and other costs (CG&E Ex. 12 at 9-11). As with the unbundled transmission rate components, the resultant distribution rates are set out in Revised Schedules UNB-1, UNB-7.1 and UNB-7.2[5] (CG&E Ex. 23).

3. Other Unbundled Components (Section 4928.34(A)(3), Revised Code)

This section requires that all other unbundled components required by the Commission in the rate unbundling plan must equal the costs attributable to the particular service, as reflected in the Company's schedule of rates and charges.

CG&E contends that, consistent with the provisions of Section 4928.34(A)(3), Revised Code, and Rule 4901:1-20-03, App. A, Part (C)(4), O.A.C., existing rates are unbundled to separate out certain components to be reflected in several riders for CG&E. The stipulations provide for a Universal Service Fund (USF) Rider and an Energy Efficiency Revolving Loan Fund (EERLF) Rider set out in Sections 4928.51 and 4928.61, Revised Code, for CG&E (CG&E Ex. 60 at 15). On July 13, 2000, ODOD filed an application with the Commission pursuant to Sections 4928.52 and 4928.62, Revised Code, regarding the establishment of USF and EERLF riders. ODOD has determined that the USF rider should be $0.0002442/kWh and that the EERLF rider should be

5 In the case of customers on special contracts, the charges for distribution, transmission, ancillary services, kWh tax, the universal service fund, and the energy efficiency fund are those charges that would apply if the customer were served on an applicable rate schedule (CG&E Ex. 23, at UNB-7.1 at 17-19).

$0.00010758/kWh. Attached to the application were supporting calculations to justify the riders. ODOD has allocated to CG&E $4,900,898 of the total $64.6 million annual target for USF funding and $2,159,262 of the total $15 million annual target for EERLF funding (ODOD application, attachments D and E). In its application, as amended on July 17, 2000, ODOD has requested that the USF rider take effect September 1, 2000, and the EERLF take effect January 1, 2001, both on a bills rendered basis.

4. Unbundled Generation Component (Section 4928.34(A)(4), Revised Code)

Prerequisite (A)(4) requires that the unbundled components for retail electric generation service in the rate unbundling plan must equal the residual amount remaining after the determination of the transmission, distribution, and other unbundled components, and after any tax related adjustments as necessary to reflect the effects of the amendment of Section 5727.111, Revised Code.

CG&E states that consistent with the provisions of Section 4928.34(A)(4), Revised Code, the component for retail electric service in CG&E's unbundled rates is the residual amount remaining after determination of the transmission, distribution, and other unbundled components, as further adjusted to reflect the effect of tax changes attributable to amendment of Section 5727.111, Revised Code, by SB3. CG&E states that, as required by Section 4928.40(C), Revised Code, CG&E has calculated a five percent reduction in the unbundled generation component for residential customers. CG&E and the parties to the stipulations have agreed to such an adjustment for residential customers (CG&E Ex. 50 at 11-12). CG&E states that, under the stipulations, it has agreed to forego its statutory right to seek reduction of this discount during the MDP because all shopping credits have been set and fixed during the MDP and are not subject to adjustment (CG&E Ex. 60 at 11-13).

5. Cap on Unbundled Components (Section 4928.34(A)(6), Revised Code)

This provision requires that the total of all unbundled components is capped and, during the MDP, will equal the total of rates in effect on the day before the effective date of SB3. The cap will be adjusted for changes in taxes, the USF rider, and the temporary rider under Section 4928.61, Revised Code.

CG&E argues that consistent with Section 4928.34(A)(6), Revised Code, and Rule 4901:1-20-03, App. A, Parts (C)(5)(b) and (D), O.A.C., the total of all unbundled components of the CG&E's unbundled rates are capped, with limited statutory exceptions, during the MDP. CG&E contends that the total of all unbundled components of existing rates equals the rates and charges of the bundled components except for adjustments to reflect changes in taxation effected by SB3, the USF and EERLF riders (CG&E Ex. 12 at 11-12). Further, CG&E states that it initially unbundled existing rates to reflect components representing its transition charges, including separation of RTC and GTC

(CG&E Ex. 12 at 31-40; and CG&E Ex. 23 at UNB-1, UNB-7.1). However, the stipulations have substantially modified the originally proposed unbundled rates for RTC and GTC (CG&E Ex. 60 at 11-14). The result of the stipulations is that CG&E is no longer requesting any GTC recovery or generation-related cost deferrals to the next rate case. Instead, CG&E is requesting an RTC that reflects new and existing regulatory assets approved by the Commission.

6. Compliance with Commission Rules (Section 4928.34(A)(7), Revised Code)

This section requires the rate unbundling plan to comply with any rules adopted by the Commission under division (A) of Section 4928.06, Revised Code[6]. The rules adopted by the Commission regarding unbundling of rates are set forth in Rule 4901:1-20-03, O.A.C., Appendix A. The portions of the Appendix that address the unbundling of separate rate components are covered in the discussion above of the various rate unbundling provisions included in the Company's plan, as amended by the stipulation.

CG&E's compliance with the provisions of Parts (A) through (D) of Appendix A is discussed in the immediately preceding sections, which address the unbundling of the separate rate components. Compliance with Parts (E), (F) and (G) are addressed by CG&E witnesses Steffen, Morris, Jett, and Pefley and are supported by the UNB schedules, the OSP stipulation in 00-813, and the transition plan stipulation.

7. Elimination of Gross Receipt Tax Effect (Section 4928.34(A)(15), Revised Code)

This Section requires that all unbundled components be adjusted to reflect the elimination of the gross receipts tax imposed by Section 5727.30, Revised Code.

CG&E states that the stipulations permit CG&E to defer and recover through the RTC the financial reporting impact of the Ohio excise tax overlap (CG&E Ex. 60 at 6; and CG&E Ex. 77 at 4). CG&E believes that this mechanism is envisioned by, and consistent with, the requirements of Section 4928.34(A)(6), Revised Code, which, in part, provide that the effect on customer rates resulting from such tax overlap "shall be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders."

6 Section 4928.06, Revised Code, directs the Commission to enact rules to effectuate commencement of competitive retail electric service. The Commission has enacted rules in compliance with this statute through its various generic rule proceedings.

AK Steel's Objections to CG&E's Unbundling Plan

AK Steel's primary objection to CG&E's unbundling plan is that CG&E's functional cost-of-service study that is used to unbundle retail rates assigns distribution costs to transmission service voltage customers (rate Schedule TS) who do not use the distribution system. AK Steel states that CG&E's unbundling analysis is based on the CG&E's cost-of-service study submitted by CG&E in its most recent electric rate case in 1992, Case No. 92-1464-EL-AIR (Tr. I at 8). This study is presented in Schedule UNB-4 of the Company's filing in this case.

AK Steel states that, as a result of the unbundling analysis required by SB3 and the Commission's regulations, the original cost-of-service study had to be unbundled and functionalized into distribution, transmission, and generation cost functions. Some of the expenses and plant accounts in the original 1992 cost of service study were already reflected on a functionalized basis. For example, direct production plant, distribution plant, and transmission plant were separately identified in the cost-of-service study and allocated to customer classes on a functionalized basis. Other costs, however, such as administrative and general expenses (A&G) were not functionalized in the original study, since there was no need to do so in order to produce bundled rates. To fully functionalize all costs, in order to develop unbundled rates, AK Steel contends it was necessary for the Company to develop a functional analysis of the remaining expenses and plant accounts; principally, A&G expenses, general and intangible (G&I) plant, common plant, and property taxes.

AK Steel argues that, although CG&E's functional cost analysis is based on the 1992 cost-of-service study (UNB Schedule 4), AK Steel witness Baron testified that CG&E has erred in the development of its unbundled distribution, transmission and generation costs because it has inappropriately functionalized A&G expenses, property taxes, G&I plant, and common plant. AK Steel believes that the errors associated with this misfunctionalization produce unjust and unreasonable rates, particularly for the transmission service class (AK Steel Ex. 13 at 41). For example, AK Steel contends that CG&E has produced unbundled tariffs for the transmission service voltage class that include a distribution charge when there are no distribution costs associated with serving this class (Tr. I at 71). CG&E's proposed unbundled tariff for Rate Schedule TS reflects a charge of $0.502 per kW for distribution service. According to AK Steel, the distribution rate for Rate Schedule TS should be $0 (AK Steel Ex. 13 at 9).

AK Steel contends that in the 1992 cost-of-service study there were 34 customers taking service on Rate Schedule TS. Those customers were assigned $15,746 of net distribution plant costs, exclusively associated with meters. No such equipment (other than $15,746 of meters) is required to serve the 34 TS customers. In its unbundling analysis, CG&E assigned $473,979 to Rate Schedule TS for G&I plant associated with distribution (Tr. I at 72). The Company assigned $473,979 of G&I plant to support a distribution investment of $15,746 (Tr. I at 73). According to AK Steel, this amounts to a G&I support ratio of 30 times the underlying distribution net plant. AK Steel further argues that CG&E only assigned $361,244 of general and intangible plant to the Secondary Distribution Small customer class to support over $27 million in distribution net plant (Tr. I at 73). The G&I support ratio for this class is .013 or 1.3 percent.

AK Steel asserts that similar implausible results are produced in the Company's analysis of A&G expenses that support distribution costs. In the development of its unbundled rates in this proceeding, the Company has assigned $485,569 of customer account expense to rate schedule TS to service 34 transmission service customers (Tr. I at 6-12). At the same time, the Company has assigned $370,077 to the Secondary Distribution Small class to support customer billing for 31,000 customers (Tr. I at 79). AK Steel argues further that, in CG&E's unbundling analysis, the Company has calculated that $2,231,007 of property taxes (out of this $6.2 million total) is associated with distribution property for Rate TS, even though it only has $15,746 of net distribution plant that is associated with meters. According to witness Baron, the underlying allocation of costs that is reflected in current bundled rates (from the 1992 cost of service study) is the appropriate source to functionalize costs for use in unbundling in this proceeding. AK Steel requests that CG&E's unbundling and functional cost analysis be rejected.

AK Steel also argues that, should the Commission find that CG&E is entitled to receive regulatory transition costs, these charges must be allocated on a cost-of-service basis.

Commission Conclusion

CG&E and our staff argue that AK Steel's arguments against the Company's rate unbundling plan are without merit. After reviewing the arguments, the Commission agrees. As testified to by Company witness Steffen, CG&E began its rate unbundling with its current transmission and distribution revenue requirements which were computed based upon a functionalization review of the cost-of-service study in CG&E's last rate case, Case No. 92-1464-EL-AIR (CG&E Ex. 12 at 8-9). The revenue requirements were adjusted for the effects of SB3 tax changes. Following the formula set forth in SB3, CG&E subtracted the transmission component revenue requirement, determined by applying FERC tariff rates pursuant to Section 4928.34(A)(2), Revised Code, from the combined transmission and distribution revenue requirement, to arrive at the unbundled distribution component revenue requirement (CG&E Ex. 23 at UNB-6.1 at 11). Company witness Steffen, at hearing, stated that the unbundled costs are a direct result of following the statutory requirements of SB3 (Tr. I at 75).

We find that the unbundling plan agreed to by the parties to the transition plan stipulation is reasonable and consistent with Section 4928.34, Revised Code. To adopt AK Steel's position would result in altering the cost allocations established in the 1992 rate proceeding and shift costs among the different rate classes in a manner not intended by the legislation. Adoption of AK Steel's recommendations could result in rates for certain classes that may exceed the statutory cap set forth in Section 4928.34(A)(6), Revised Code. The evidence of record shows that the unbundling plan proposed by the Company follows the intent of Section 4928.34, Revised Code. In unbundling the rates for each customer class, the Company had to follow the requirements of SB3, which not only dictated the unbundled transmission rate to be a FERC rate, but also necessitated the use of the CG&E 1992 cost-of-service study. Although certain allocations of costs may appear to be incongruous, we find that CG&E has followed the statutory scheme in unbundling its rates. Further, one of the purposes of this proceeding is to establish unbundled rates based on the already adopted cost-of-service study, not to alter that study or to determine whether a more appropriate allocation of costs should be used to unbundle rates. To do so would clearly be inconsistent with the mandate of Section 4928.34(A)(6), Revised Code, which requires the unbundling of the rates in effect on the day before the effective date of SB3. We also find that the transition charges for each class proposed in the stipulation reflect the cost allocations from the Company's last rate case and, accordingly, are based on the 1992 cost-of-service study. Therefore, we find such allocation of regulatory transition costs to be reasonable.

With regard to the establishment of the USF and EERLF riders, we note the Commission by entry issued on August 17, 2000 approved a USF rider for CG&E of $0.0002442/kWh effective September 1, 2000, and a EERLF rider of $0.00010758/kWh effective January 1, 2001.

After reviewing the testimony and exhibits submitted by CG&E that support the proposed unbundled rates, and having considered and rejected the objections and arguments raised by AK Steel, we find that the Company has satisfied the statutory requirements for the unbundling of rates set forth in divisions (A)(1) to (7), (15) of Section 4928.34, Revised Code.

C. Transition Revenues

Section 4928.34 (A)(12), Revised Code, requires that the transition revenues authorized under Sections 4928.31 to 4928.40, Revised Code, must be the allowable transition costs of the Company pursuant to Section 4928.39, Revised Code, and that the transition charges for customer classes and rate schedules are the charges under Section 4928.40, Revised Code. Section 4928.39, Revised Code, requires the Commission to determine the total allowable amount of the Company's transition costs to be received by the Company as transition revenues. Such transition costs must meet the following criteria:

(1) The costs were prudently incurred.

(2) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(3) The costs are unrecoverable in a competitive market.

(4) The utility would otherwise be entitled an opportunity to recover the costs.

Section 4928.40(A), Revised Code, provides, among other things, that a company may create additional regulatory assets, with notice and an opportunity to be heard through an evidentiary hearing, as long as the company does not increase the level of regulatory transition charges above those contained in the company's existing rates.

CG&E's request for transition cost recovery in its original transition plan filing totaled $1.518 billion, including carrying charges of $311 million, and deferral and recovery of $280 million of transition implementation costs, including carrying charges, until its next distribution rate case (CG&E Ex. 65 at Ex. WPLJP-8a). CG&E's request included $563 million of generation plant transition costs (CG&E Ex. 13 at 12). Furthermore, CG&E sought the right to modify its request for transition revenues for the costs of power purchased to provide reliable service.

According to CG&E, the stipulations significantly modify and reduce CG&E's request for transition cost recovery to $884 million plus carrying costs and purchased power deferrals necessary to maintain an adequate operating reserve margin (CG&E Ex. 77 at 4-5, Ex. LJP-R-1, Ex. LJP-R-2). The transition plan stipulation provides CG&E with no GTC recovery and places the electricity market price risk entirely on CG&E. The stipulations do provide CG&E recovery of previously approved regulatory assets totaling $401 million and new regulatory assets totaling at least $483 million (CG&E Ex. 60 at 6-7; CG&E Ex. 50 at Ex. JPS-SUP-5; and CG&E Ex. 77 at Ex. LJP-R-2).

CG&E states that the difference between CG&E's original request for $364 million of previously approved regulatory assets and the request, as modified by the stipulations, of $401 million is broken down as follows: $26,571 for grossed-up carrying charges recommended by staff in its Staff Report; an adjustment of $1,548,386 for regulatory liabilities for three percent and four percent investment tax credit related to generation; an adjustment to the Statement of Financial Accounts Standards (SFAS) 109 balance of $27,299,428 to properly reflect IRS normalization rules; an adjustment to restore the regulatory asset balance previously reduced by CG&E due to staff's recommendation F-9 on page 30 of the Staff Report for franchise and municipal taxes; and an update from estimated to December 31, 1999 year end balances (CG&E Ex. 50 at 43-44, and Ex. JPS-SUP-5).

The new regulatory assets requested include the $115 million, before carrying costs, of transition implementation costs for which CG&E originally sought deferral, and deferral of the shopping incentive, Ohio excise tax overlap, and purchased power costs[7] (CG&E Ex. 12 at JPS-5; CG&E Ex. 60 at 6-7, and CG&E Ex. 77 at 3-5, LJP-R-1).

Set forth below are the issues and objections raised by AK Steel and Shell to the establishment of regulatory transition charges and the recovery of transition revenues as proposed by the parties to the transition plan stipulation.

1. Stranded Generation Benefits

AK Steel argues that, while CG&E has withdrawn its claim for GTC and now claims only RTC costs, an analysis of the generation costs shows that CG&E has stranded generation benefits which must be "netted" against any RTC claimed by the CG&E. AK Steel argues that stranded benefits occur when unregulated market prices will be so high as to provide excessive returns on the investments made under regulation. According to the testimony of AK Steel witness Falkenberg, these stranded benefits amount to $957 million (AK Steel Ex. 15 at 64). Mr. Falkenberg testified that when only three mistakes in the CG&E study were corrected, the Company had stranded generation benefits (*Id.* at 49).

Mr. Falkenberg also took issue with CG&E's market price model used to determine the value of generation assets. Mr. Falkenberg developed an independent market price and stranded cost forecast that was substantially different from that developed by CG&E witness Pifer. Mr. Falkenberg testified that only three variables are key in the determination of market price forecasts. They are: (1) fuel prices; (2) cost of new capacity; and (3) reserve margins (*Id.* at 10). Mr. Falkenberg testified that recent natural gas prices from futures contracts and current trading illustrates that gas prices used in CG&E forecast are simply too low.

With regard to forecasting cost and performance of new merchant plants, Mr. Falkenberg pointed out that Dr. Pifer's study erred in its computation of the real fixed charge rate, the variable that determines the annual cost of ownership of new plants, and has a direct impact on market prices. Mr. Falkenberg contends that Dr. Pifer's forecast understates these costs by 16 percent (AK Steel Ex. 15 at 38). Mr. Falkenberg contends that this mistake alone overstates CG&E's stranded costs by $183 million in Dr. Pifer's study (*Id.* at 39).

On the subject of reserve margins, Mr. Falkenberg presented a forecast premised on a 15 percent reserve margin, a level Mr. Falkenberg considers reasonable and the

---

7 The $115 million of new regulatory assets includes $3 million for Transition Plan Case expense, $50,000 for the Commission Transition Cost Consultant, $4.6 million for the Commission mandated Consumer Education Program costs, $65 million for upgrades to CG&E's information and customer service systems, $15 million of otherwise unrecoverable costs associated with the MISO, and $28 million of costs to establish the EWG (CG&E Ex. 12 at Ex. JPS-5).

consensus of experts' opinions (AK Steel Ex. 15). This is in contrast to Dr. Pifer's Energy Only (no reserve margin) market concept. Mr. Falkenberg argues that Dr. Pifer's analysis suggests that reliability will be just fine as reserve margins drop to two percent in the years ahead.

Beyond the market price model, AK Steel argues that CG&E ignores the plants that, even under its own calculations, have stranded benefits. According to Dr. Pifer's study, only the Zimmer and Woodsdale combustion turbine generators have stranded costs. Mr. Falkenberg calculated what he believes to be stranded generation benefits of $957 million as summarized on AK Steel Ex. 8. AK Steel argues that Section 4928.39, Revised Code, requires the transition cost must be "legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service." AK Steel contends that any regulatory transition costs the Commission approves would have to be netted against stranded generation benefits.

Another problem with the Company's forecast, according to AK Steel, is that CG&E witness Speyer uses a carbon tax on coal that he presumes will add more than a billion dollars in costs to the CG&E generators. Mr. Falkenberg testifies that this assumption is speculative and biased inasmuch as no one knows what the U.S. Senate will do about global warming, or if the utility industry will even be affected (AK Steel Ex. 15 at 7-8 and 41-48). As a result, AK Steel contends that the CG&E study overstates stranded costs by $350 million (AK Steel Ex. 15 at 48). AK Steel argues that, if these mistakes and other biases were corrected, the CG&E study would replicate the results of Mr. Falkenberg's study that shows the Company has $957 million in stranded benefits (AK Steel Ex. 8).

Shell supports AK Steel's arguments regarding stranded generation benefits. Shell argues in its objection and on brief that the stipulation's approach to transition costs fails to demonstrate that the amount of stranded costs recovered (whatever it might be) is a "net" figure, *i.e.*, the result of considering both losses and gains realized as a result of transitioning to a competitive market place. Shell disagrees with CG&E's position that, because SB3 does not make reference to transition benefits or negative transition costs, there is no legal requirement for such an offset. Further, Shell disagrees with CG&E's position that the word "net" in SB3 does not imply offsetting market valuations below book value on some plants with market valuations above book value on others. Shell argues that the testimony of Mr. Falkenberg illustrates that, far from having stranded generation costs, the market value of CG&E's generation portfolio substantially exceeds its book value, thereby providing the utility a market premium. Shell argues that the stipulation fails to satisfy one of the statute's fundamental criteria for transition cost approval, provides a potential windfall to CG&E in the form of generation premiums and inflated transition cost recoveries, and dramatically disadvantages ratepayers.

Shell also argues that the stipulation, if approved, would deny ratepayers a share of the market premium associated with generation assets. According to Shell, these generation assets have a book value of approximately $1.59 billion (Shell Brief at 39). Shell contends that, if CG&E transferred these assets to an EWG, it would substantially harm ratepayers by denying them any share of the market premium associated with this portfolio of generation assets. Shell argues that in originally valuing its generation assets for GTC purposes, CG&E relied on unrealistically low projections of future wholesale power market prices which is the most significant factor in valuing generation assets. Shell states that, from a review of Company Ex. 33, Ex. HWP-2, 1 of 1, the firm power price assumed in 2001 by CG&E's analysis contrasts sharply with CG&E's own recent purchase power costs of $0.0297 in 1998 and $0.0334 in 1999. Shell believes that a wholesale market price substantially higher than that utilized by CG&E is needed to adequately value the utility's generation portfolio. Shell submits that by simply employing a wholesale market price projection more in keeping with CG&E's own actual recent experience in wholesale power markets would greatly reduce, if not eliminate completely, the supposedly uneconomic generation costs identified by CG&E's analysis. Shell also contends that CG&E's analysis contains several other dubious assumptions that, when corrected, produce even larger stranded benefits. For example, CG&E discounts the projected earnings streams for its generating plants using a 13.63 percent equity cost and a capital structure comprised of 49 percent equity and 51 percent debt. Another questionable assumption, according to Shell, concerns the retirement dates for the Beckjord, Conesville, Stuart, and Zimmer generating plants. CG&E owns each of these plants in partnership with American Electric Power's (AEP) subsidiary, Columbus Southern Power Company. CG&E has assumed much earlier retirement dates than those that were assumed by AEP's Transition Plan filing (Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP).

CG&E disputes the finding of Mr. Falkenberg and disagrees with the arguments raised by AK Steel and Shell. CG&E contends that Mr. Falkenberg's future fuel price assumptions lack reliability. CG&E argues the single most significant variable in the forecast is future natural gas prices. CG&E states that low price gas forecasts tend to increase the calculated stranded costs, while high price gas forecasts tend to decrease stranded costs.

CG&E states that Mr. Falkenberg relies upon the Energy Information Agency's (EIA) Annual Energy Outlook, 2000 (AEO 2000) forecast as his sole source of fuel price information. CG&E argues that there are several other more credible fuel forecasts. Each of the other forecasts project lower future fuel prices than AEO 2000. CG&E also contends that Mr. Falkenberg did nothing to compare AEO 2000 to the other various forecasts that are credible, or even to evaluate the historical accuracy of any of these forecasts (Tr. IV at 149, 156). Additionally, both AEO 2000 and AEO 1999 demonstrate that EIA's forecasts tend to be considerably higher than other fuel forecasts that Mr.

Falkenberg himself concedes are credible (*Id.* at 150-154, CG&E Ex. 73 at 99). EIA's average forecast price at the wellhead demonstrated an average absolute percentage forecast error of 72.2% (Tr. IV at 160-164; and CG&E Ex. 67 at 81, 84, 90).

CG&E argues that Mr. Falkenberg's market structure assumption is equally biased, and ignores the laws of economics altogether. As an economist, Dr. Pifer assumed that market forces, the laws of supply and demand, will ultimately determine the price at which electricity will be sold in the future, and that this price will reflect whatever reserve capacity market participants are willing to pay. Mr. Falkenberg, however, opines that these economic market forces should be ignored, and instead asserts that a 15 percent reserve margin must be factored into the market structure analysis. CG&E argues that the effect of Mr. Falkenberg's 15 percent reserve requirement assumption is that prices, and thus utility income, are assumed to be higher than the economic laws of supply and demand would otherwise dictate (Tr. IV at 178).

CG&E asserts that Mr. Falkenberg did not evaluate the risk of future environmental regulation as it relates to the potential increased costs of NOx, SO2, PM 2.5, or Mercury regulations. Mr. Falkenberg evaluated only the risk of future tightened CO2 restriction resulting from implementation of the Kyoto protocols currently under consideration by the U.S. Senate to reduce greenhouse gases (*Id.* at 127-129, 168). CG&E contends that Mr. Falkenberg has assumed that no increased environmental regulation, of any sort, is likely, despite his failure to evaluate what these other environmental regulations might be. CG&E also notes that Mr. Falkenberg himself concedes that, by comparison to EIA, Mr. Speyer's use of a $10 per ton figure is conservative. CG&E argues that Mr. Falkenberg's testimony regarding the existence and amount of stranded costs, or stranded benefits, is simply not credible and should be ignored.

With regard to the issue of netting of market premiums against transition costs raised by Shell and AK Steel, CG&E argues that SB3 provides it an opportunity to recover its revenue requirement through the transition charge from customers that choose to switch electric suppliers and that the netting recommendation contradicts the ratemaking statutes in effect and newly created SB3. Under the framework of these laws, unbundled rates plus transition charges must give CG&E the same opportunity to collect its revenue requirement as CG&E has under its current bundled rates. CG&E argues that, by basing its transition charge on the net market value of all of CG&E generation assets as proposed by AK Steel and Shell, the Commission would be denying CG&E an opportunity to collect its revenue requirement associated with the Commission approved book value of assets from CG&E's last rate case and with previously approved regulatory assets. CG&E also contends that, although it is not requesting to recover any GTC as part of the stipulation, that amount was fully netted (CG&E Ex. 22 at HWP-5 at 6; CG&E Ex. 13 at LJP-1; and CG&E Ex. 50 at JPS-SUP-6).

After considering the arguments raised above, the Commission comes to the conclusion that CG&E has put forth sufficient evidence to support its argument that there are no stranded generation benefits that should offset the regulatory transition cost proposed by the stipulations. The Commission finds that Dr. Pifer's market forecast for electric power and future fuel price forecasts is reasonable. Dr. Pifer based his future fuel prices on a broader based analysis than that used by Mr. Falkenberg and, therefore, should have a greater degree of reliability. Further, the record shows that the EIA has had problems with accurately forecasting coal and natural gas prices used in its Annual Energy Outlook. We also believe Dr. Pifer's market structure assumptions are reasonable. Dr. Pifer assumed that market forces, the laws of supply and demand, will ultimately determine the price at which electricity will be sold in the future, and that this price will reflect whatever reserve capacity for which market participants are willing to pay. The use of a 15 percent reserve margin used by Mr. Falkenberg is unlikely to hold true in a competitive market. We further find that changes in environmental regulation that could occur may have an affect on market forecasts and should appropriately be considered as Mr. Speyer has done. From the evidence presented, Mr. Speyer's estimated costs of environmental compliance is conservative and not unreasonable.

With regard to the issue of "netting" stranded generation benefits, believed to exist by AK Steel and Shell, with stranded regulatory costs, the Commission finds that the stipulation provides an equitable resolution of this matter. The Company has agreed to forego asserting a claim for stranded generation costs that they calculate on brief to be approximately be $470 million on a netted basis (CG&E Reply Brief at 22; CG&E Ex. 22 at HWP-5 at 6; CG&E Ex. 13 at LJP-1 at footnote 3; and CG&E Ex. 50 at JPs-SUP-6). Further, the parties to the stipulation have agreed, based on all the terms and conditions that are set forth in the stipulation, that there is no further netting or adjustments of any kind to CG&E's transition cost recovery that are necessary (CG&E Ex. 60 at 7). Additionally as discussed above, the Commission does not agree with Mr. Falkenberg's stranded benefit analysis and, therefore, cannot find that there are stranded benefits that exceed the amount of the GTC that CG&E has agreed to forego recovery of as part of the stipulation. Based upon the above finding, the Commission finds that there are no stranded generation benefits that should offset the regulatory transition cost proposed by the transition plan stipulation.

2. Existing Regulatory Assets

AK Steel takes exceptions with a number of accounting treatments used by CG&E in calculating its existing regulatory assets to be recovered in its RTC. AK Steel argues that the Company mischaracterized the accumulated deferred income taxes (ADIT) as a component of the GTC rather than the RTC. According to AK Steel witness Kollen, the ADIT is a regulatory liability that should be subtracted from regulatory assets and provided to ratepayers through a reduced RTC rather than the GTC (AK Steel Ex. 14 at 21). Mr. Kollen also states that the FERC Uniform System of Accounts classifies ADIT as a "Deferred Credit," not as "Utility Plant" and, therefore, CG&E accounting is not consistent with the FERC accounting standards. AK Steel argues that the Commission should recognize the Company's ADIT associated with all its generating units as a regulatory liability and reduce the Company's regulatory asset transition cost claim to be recovered through the RTC, regardless of whether the Commission accepts or rejects the stipulation.

AK Steel also argues that the SFAS 109 regulatory tax assets and liabilities must be stated on a net present value basis because there are no carrying costs associated with these future taxes under existing cost-based regulation (AK Steel Ex. 14 at 25). Further, AK Steel takes issue with the Company's proposal to include in the distribution component of unbundled rates a hypothetical SFAS 109 regulatory asset for municipal and franchise tax temporary differences the Company projects will exist in 2002. AK Steel argues that the Company has acknowledged that it will not record and is not required to record such a regulatory asset at December 31, 2000 (AK Steel Ex. 14 at 25-26). Thus, according to AK Steel, it would be absurd to allow the Company to create a hypothetical SFAS 109 regulatory asset at December 31, 2000, that will not exist at that date and then to recover this hypothetical cost from ratepayers in the distribution component of unbundled rates.

AK Steel also disagrees with the Company's excess deferred income tax (EDIT) and the related SFAS 109 tax benefits. The Company has removed the entirety of the EDIT tax benefits from the ADIT component of its net book value computations; thereby increasing its generation transition costs claims. AK Steel argues that the EDIT amounts represent taxes prepaid by ratepayers at tax rates higher than they are currently. Historically, these EDIT prepaid taxes benefits were amortized back to ratepayers over the remaining lives of the underlying assets. The Company removed EDIT benefits of $11.378 million (AK Steel Ex. 14 at 28). In addition, AK Steel argues that the removal of the EDIT regulatory liability from the ADIT utilized by the Company in its SFAS 109 regulatory asset computations improperly increased the Company's SFAS 109 regulatory asset transition cost claim by $19.186 million on a nominal dollar basis, or $8.068 million on a net present value basis (AK Steel Ex. 14 at 28). AK Steel contends that the EDIT and the related SFAS 109 tax benefits belong to ratepayers pursuant to existing cost-based regulation (AK Steel Ex. 14 at 29 and Tr. VI at 33-34). According to AK Steel, the Commission should reject the Company's attempt to unilaterally appropriate these regulatory liabilities in order to increase its claimed regulatory asset transition costs.

Similar to the EDIT, AK Steel argues that the Company failed to reduce its regulatory or generation transition cost claims by the net present value of its investment tax credit (ITC) amounts. AK Steel argues that the ITC and the related SFAS 109 tax benefits belong to ratepayers pursuant to existing cost-based regulation (AK Steel Ex. 14 at 35 and Tr. VI at 33-34). AK Steel requests the Commission reject the Company's attempt to unilaterally appropriate these regulatory liabilities in order to increase its claimed regulatory asset transition costs.

AK Steel also argues that there will be no normalization violation if the Commission provides the ADIT, EDIT, ITC, and related SFAS 109 regulatory liability tax benefits to ratepayers through the RTC. Mr. Kollen stated that the normalization requirements of the Internal Revenue Code of 1986, as further described in the IRS regulations and as further interpreted for specific taxpayers in the IRS Private Letter Rulings, provide that there is no normalization violation if such ADIT benefits are provided to ratepayers no more rapidly than the time period over which the underlying costs are recovered through regulated rates. All transition costs allowed by the Commission in this proceeding will be recovered in ten years or less which is more than the recovery of generation transition costs of five years or less under a GTC.

Lastly, AK Steel requests that, if the Company sells its generating assets, then the related SFAS 109 amounts will be reversed (eliminated) from the balance sheet, with no gain or loss recognized. Thus, the unamortized SFAS 109 regulatory asset transition cost balance as of the date of the sale should be removed from the RTC. The Commission should establish this treatment in its order in this proceeding in order to assure that ratepayers are not penalized in the event of a sale of the generating assets (AK Steel Ex. 14 at 18-19).

CG&E witness Mr. Hriszko disagrees with Mr. Kollen's characterization of the ADIT. Mr. Hriszko testified that the IRS views ADIT as an interest-free loan from the federal government (CG&E Ex. 76 at 3). Similarly, Mr. Kollen's treatment of EDIT balances in the Company's SFAS 109 computation cannot be justified according to CG&E. Congress established specific rules concerning how the benefits of EDIT were to be shared between ratepayers and shareholders. CG&E argues that these rules would be violated by the treatment that Mr. Kollen proposes (*Id.* at 8). Mr. Hriszko states in his rebuttal testimony, that the adjustments that Mr. Kollen proposes violate the tax normalization rules. The IRS has ruled that, where the cost of property is no longer included in the calculation of cost of service for ratemaking purposes, the inclusion of tax benefits from such property is a violation of the tax normalization rules (CG&E Ex. 71 at 31). CG&E believes it is clear that the Ohio General Assembly has directed this Commission to resolve deregulation issues now so that deregulation of the generation market occur within Ohio no later than January 1, 2001. Thus, according to CG&E, the Ohio General Assembly clearly contemplated that the current IRS position regarding tax treatments of these items would control, and that CG&E would necessarily set its regulatory asset balances recognizing the existing position of the IRS.

CG&E disagrees with Mr. Kollen's treatment of SFAS 109 regulatory asset for municipal and franchise tax temporary differences. CG&E argues that Section 4928.34 (A)(6), Revised Code, expressly allows the Company to recover costs associated with statutory tax changes and that it is following the recommendation for collection of such assets set forth in the Staff Report.

The Commission finds that $401.4 million for jurisdictional regulatory assets quantified by CG&E witness Steffen is reasonable and based upon the Staff Report adjustments to the Company's original transition plan filing (CG&E Ex. 50 at JPS-SUP-5 at 1). We find that the tax-related adjustments to these regulatory assets proposed by AK Steel witness Kollen would not be in keeping with the tax normalization rules established by the IRS. As Mr. Hriszko testified, Mr. Kollen's proposal would decouple tax attributes from the assets that generated the tax attributes, namely generation plants. By offsetting these tax attributes against regulatory assets, a pattern would be established that would return these tax attributes to the ratepayer over a period of time that is different than the period of time over which the tax attributes would normally reverse (CG&E Ex. 76 at 2). Accordingly, we will not adopt the adjustments to the RTC proposed by Mr. Kollen above. The Commission has already approved $401 million of CG&E's regulatory assets and, therefore, found that amount prudent. The testimony of CG&E witnesses Steffen and Pefley support findings that such transition costs were prudently incurred; legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service; are unrecoverable in a competitive market, and that the utility would otherwise be entitled an opportunity to recover the costs.

3. CG&E's Request to Defer and Recover Certain Costs as Regulatory Assets

The parties to the transition plan stipulation have requested accounting authority to create the necessary regulatory assets, defer the costs of those assets, and recover them through an RTC. Such costs are associated with purchased power, litigation of this proceeding, establishing an EWG, and shopping incentives, among others. AK Steel contends that many of the items in the stipulation that CG&E seeks to have accounting authority to defer and recover as regulatory assets do not meet the criteria established for transition costs under Section 4928.39, Revised Code, as discussed above. Set forth below are the objections raised by AK Steel and Shell, the responses to those objections, and the Commission's findings.

Objections of AK Steel and Shell

One of the costs which CG&E is asking to be deferred as a transition cost is purchased power costs sufficient to maintain an adequate operating reserve margin as determined by CG&E. AK Steel argues that CG&E does not show anywhere in its transition plan filing or stipulation the amount of money claimed, forecasted, or desired for purchased power. AK Steel also argues that, since the 1999 fuel and purchased power costs, including the summer 1999 price spikes, are already being recovered in the EFC, a separate deferral of purchased power costs clearly would be a double and improper recovery. AK Steel witness Baron testified that there is no basis to determine that these costs are prudently incurred. Neither are these purchased power costs directly assignable or allocable to retail electric generation service provided to electric consumers who shop. Under the stipulation, deferred purchased power expenses will be charged to all ratepayers through the RTC, both those who shop and those who remain CG&E customers. AK Steel witness Baron believes that, under traditional standard ratemaking methodologies, shopping customers who do not impose any purchased power expenses on CG&E should not be assigned these costs, contrary to the stipulation.

AK Steel next takes issue with CG&E's proposals to pay $1.5 million in litigation reimbursement to be shared, and agreed upon, by, and among, active intervenor signatory parties to the stipulation. The intervenors are given voting rights to be used to disburse the money with agreement of 75 percent of the active parties constituting a binding vote as to reimbursement. AK Steel argues that this proposal is inappropriate and illegal and does not comply with Section 4928.39, Revised Code. AK Steel further asserts that the costs are not prudently incurred, because the Company is not obligated or required in any case to pay the legal fees of its opponents but only its own legal fees. AK Steel knows of no past precedent to allow a public utility to pass on to its ratepayers the legal costs of intervenors.

AK Steel's third issue concerns the deferral and recovery of $28 million associated with CG&E's plan to sell off all its generating units to an affiliated EWG. The costs are for start up and debt financing and refinancing (Tr. I at 52). AK Steel witness Kollen testified that these costs are discretionary and are not required by SB3. Thus, the costs cannot be considered just and reasonable transition costs as a threshold matter. Further, Mr. Kollen contends that the costs to establish an EWG are not directly assignable or allocable to retail electric generation service inasmuch as it is not a retail service (AK Steel Ex. 13 at 36). AK Steel further argues that CG&E may not incur most of these costs if CG&E is able to release the generation assets from its existing first mortgage obligations without having to redeem the first mortgage bonds. AK Steel claims that this would save the Company $22.5 million dollars of the $28 million dollars requested for EWG transaction costs (Tr. III at 40).

AK Steel's final issue in this area concerns the overstatement of deferred shopping incentive transition costs and its affect on the determination of whether the Company will over recover transition cost over the next ten years. AK Steel disputes CG&E 's quantification of the level of transition revenues and transition costs that would be recovered as result of the stipulation. CG&E submitted the testimony of witness Pefley to show the level of transition costs that the Company will actually recover as a result of the stipulation (CG&E Ex. 77, LJP-R-2). Based on this analysis, the Company claims that it will under-recover approximately $153 million through the year 2010 under the Stipulation (Tr. VI at 2). Among the costs included in the Company's analysis are the amounts for regulatory assets claimed by CG&E in its original filing and supplemental filings ($401.4 million), as well as $115.6 million of implementation costs, $34.5 million of Ohio excise tax overlap, and shopping incentives of $333 million.

AK Steel witness Baron developed an analysis that estimates the level of RTC revenue recovery on a present-value basis. Mr. Baron calculated that the Company will recover RTC revenues of $651,257,591 on a present-value basis if the stipulation is approved and implemented by the Commission (AK Steel Ex. 13 at 67). This $651 million revenue amount far exceeds the regulatory assets that the Company has claimed in its filing ($401 million) or the regulatory assets that AK Steel witness Kollen has developed for CG&E ($12 million) (AK Steel Ex. 13 at 67).

AK Steel argues that, of all the costs included in the Company's analysis that it relies on to support the stipulation, the $333 million of shopping incentives is the most unreasonable. AK Steel defines a shopping credit as the additional amount of payment necessary to induce a customer to leave the incumbent utility (CG&E) and use an alternative supplier. AK Steel argues that the Company uses this exaggerated shopping incentive quantification to argue that the stipulation produces transition revenues that are lower than its claimed transition costs. AK Steel argues that CG&E has calculated shopping incentives for the first 20 percent of customers in each customer class based on a comparison of the shopping credits paid to such customers and the Company's estimated market price, as developed by CG&E's witness Pifer.

AK Steel argues that when the shopping incentive quantification used by CG&E is corrected to reflect the actual shopping incentives provided to the first 20 percent of each customer class, the Company's analysis falls apart. Mr. Baron developed the shopping incentives using the difference between the RTC that all customers will pay and the RTC net of shopping incentives that is offered to the first 20 percent of each rate class. AK Steel argues that using this interpretation of the shopping incentive produces a shopping incentive cost to CG&E of $135.8 million, instead of the Company's $333 million amount. When this value is substituted into Ms. Pefley's analysis of transition costs, it shows that CG&E will actually overrecover $425.7 million by the end of the ten-year transition period (AK Steel Ex. 20). Shell supports AK Steel's position the shopping incentive-related transition costs are overstated. Due to unrealistically low average energy prices used in the Company's calculations, Shell argues that shopping incentive-related transition costs are inflated.

Shell also takes the position that the new regulatory assets have yet to be incurred and, therefore, were not prudently incurred as required by SB3. Shell also believes that SB3 leads to the inescapable conclusion that the regulatory asset portion of the RTC charge must reflect only CG&E's previously approved regulatory assets, and that newly approved regulatory assets must be recovered within the parameters of that RTC charge. Because the stipulation would premise its RTC charge on both existing and new regulatory assets, Shell believes it violates SB3.

Shell also argues that the stipulation's request for new regulatory assets fails to satisfy SB3 in several additional respects. The proposed new regulatory assets for purchased power costs, payment of other parties' litigation costs, and the effects of any shopping incentive simply do not fall within the parameters of "regulatory assets" as defined by SB3. If anything, many of these costs, such as EWG set-up costs ($28 million) MISO costs ($15 million) and System & Business Processes ($65 million) contained in the transition implementation costs, and future purchased power costs represent the type of "going forward" costs related to the future conduct of CG&E's business that regulatory agencies consistently have refused to include in stranded cost calculations.

CG&E and Staff Responses

CG&E argues that it will incur costs associated with purchasing power to maintain an adequate reserve margin as it meets the needs of its customers who take service under CG&E's standard offer service. These costs are directly assignable to retail electric generating service. Because the mechanism to recover these costs, the RTC, is fixed by the stipulation, CG&E will have the incentive to prudently manage these costs. Additionally, these costs will be recorded on the Company's books and will be verifiable by the Commission. CG&E further argues that, since these costs will be incurred to provide regulated generation service under fixed rates, there is clearly no possible recovery through the market.

With regard to litigation costs, CG&E's argues that the limited payment of these expenses is prudent inasmuch as the Company would have spent far more on its own if the case was fully litigated. CG&E believes that, given the number of parties and witnesses, the $1.5 million is not an unreasonable sum of money nor improper to provide as part of a settlement offer. CG&E notes that the Commission will have access to the company's books and records to verify that CG&E has incurred these expenses.

CG&E also disagrees with AK Steel's EWG arguments. The Company argues that these costs are appropriately recovered under Section 4928.39, Revised Code. CG&E views these cost as the most pragmatic and economical way to comply with the Corporate Separation Plan required by Section 4928.17, Revised Code. CG&E states that it will take all measures to minimize costs of the transfer and the amount proposed to be recover represents the expected costs to accomplish this task (CG&E Ex. 39 at Ex. LJP-SUP-1, 3 and 5). CG&E states that it will record and defer the actual costs incurred, and make its books and records available the Commission for review.

CG&E asserts that Mr. Baron has mischaracterized the shopping incentive and the associated cost. Mr. Baron calculates the cost to be the difference between the shopping credit that CG&E proposes to the first 20 percent of customers who switch and the shopping credit offered to the remaining 80 percent of customers (Tr. VI at 72). This computation reflects the cost that CG&E will incur to induce 20 percent of its customers to switch. CG&E disagrees with this analysis. CG&E believes that customers will be induced to switch only if they can obtain real savings or value. The measure of this value, or inducement, will be the difference between the amount the customer is credited by CG&E for not taking generation from CG&E, and the amount the customer must pay to an alternative supplier for retail generation. According to Ms. Pefley, the inducement, or incentive to shop, is simply the difference between CG&E's shopping credit and the market price (CG&E Ex. 77 at Ex. No. LJP-R-2 at 4-5).

The staff supports the arguments made by CG&E regarding the deferral and recovery of regulatory transition costs. Because CG&E has agreed to a fixed RTC rider rate, it bears a risk of never recovering a certain portion of the deferrals based upon future, unknown, and presently unknowable market conditions. Mr. Baron's concern, of allowing CG&E to "defer purchase power costs sufficient to maintain an adequate operating reserve margin," is more an academic difference than a real issue according to staff. The stipulation does not provide any separate rate recovery of the accounting deferrals but merely provides accounting flexibility to the Company. It does not reduce the Company's risk of recovery, nor guarantee it a fixed and excessive stream of revenue. The staff notes that CG&E has waived the right to seek any rate recovery of any costs deferred pursuant to such accounting authority that are not recovered through the RTC (CG&E Ex. 60 at 6).

Staff further points out that, in Section 4928.40(b)(2), Revised Code, satisfactory shopping incentive results are referred to as one cause for the Commission to consider ending the MDP. Staff contends that the transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service (Section 4928.40, Revised Code). Staff believes that CG&E's deferral and recovery of reasonable shopping incentives provides the room for competing marketers to enter and create a viable and competitive market.

The staff also believes that the establishment of a EWG is a reasonable method both of ensuring corporate separation and of compensating CG&E for their compliance with Section 4928.17(A), Revised Code.

<u>Commission Conclusion</u>

The Commission finds that the costs of the new regulatory assets discussed above meet the requirements of Section 4928.39, Revised Code, and can be deferred for recovery through the RTC. We believe the record demonstrates that the costs subject to recovery are prudently incurred, are directly assignable to retail electric generation service provided to electric customers in this state, not recoverable in a competitive market, and would otherwise have been recoverable. Inasmuch as purchased power costs will be incurred to provide regulated generation service under fixed rates, it is reasonable to recover future costs of purchased power through the RTC. Further, we believe the Company would have spent far more on litigation if it had to fully litigate the case. The payment of other parties' legal costs under terms of this stipulation, although unique, is not unreasonable taking into account the full parameters of this case.

With respect to the recovery of EWG transition costs, the Commission finds that these costs are attributable to electric restructuring and the provision of retail electric generation service. We believe Mr. Kollen takes a too restrictive position regarding this requirement. We further find that the Company has adequately supported its projected costs of transferring its generation assets through the testimony of witness Pefley (CG&E Ex. 39).

Regarding the issue of the cost of shopping credits, SB3 permits the Commission to authorize shopping incentives in order to induce at least 20 percent of customers in each customer class to shop (Section 4928.40(A), Revised Code). The Company has projected the cost to be $333 million as opposed to $135.8 million calculated by Mr. Baron. The stipulation provides CG&E the accounting authority to create the necessary regulatory assets and defer and recover deferrals or adjustments to the amortization schedules to reflect the effect of any shopping incentives (CG&E Ex. 60 at 6). The Company argues the measure of this value, or inducement, will be the difference between the amount the customer is credited by CG&E for not taking generation from CG&E, and the amount the customer must pay to an alternative supplier for retail generation. According to Ms. Pefley, the inducement, or incentive to shop, is simply the difference between CG&E's shopping credit and the market price. The Commission finds this approach to arrive at the amount of deferred costs is reasonable and in keeping with the stipulation. The stipulation addresses the effects of any shopping incentives, not just those related to the first 20 percent of customers that switch. We further note, as pointed out by our staff, that the stipulation does not provide any separate rate recovery of the accounting deferrals but merely provides accounting flexibility to the Company. It does not reduce CG&E's risk of recovery, nor guarantee it a fixed and excessive stream of revenue. Accordingly, we are not persuaded by the arguments raised by AK Steel and Shell on this issue.

The Commission would also like to note that, inasmuch as the transition plan stipulation is a compromise involving a balancing of competing positions and does not necessarily reflect the views which one or more of the parties to the stipulation would have taken if these issues had been fully litigated, our approval of these new regulatory assets does not necessary reflect what the Commission's position would have been had not the issue been part of an all encompassing stipulation. Accordingly, our decision to accept the creation and accounting treatment of the new regulatory assets creates no precedent for any other transition plan proceeding. We further note that, although the stipulation provides for the opportunity to recover the cost of various newly created regulatory assets, CG&E 's analysis shows that at the end of 2010 the unrecovered balance of generation-related regulatory assets is projected to be approximately $153 million (CG&E Ex. 77 at LJP-R-2 at 1). The recovery mechanism for thes costs provides protection to consumers and supports the reasonableness of approving the creation of these new regulatory assets.

4. Transition Costs Compliance with Statutory Requirements

Shell argues that the stipulation's treatment of regulatory transition costs violates SB3 in a variety of fundamental respects. Shell states that the Commission must determine the total allowable amount of the transition costs of the utility to be received as transition revenues and that these costs must meet the standards of Section 4928.39 (A) through (D), Revised Code. Shell contends that the stipulation's treatment of transition costs violates each of the foregoing statutory provisions.

Shell contends that nowhere does the stipulation purport to identify the maximum level of transition costs authorized for recovery by CG&E. In fact, the stipulation makes plain that its proposed transition revenue recovery is "not limited to" the regulatory assets it identifies. AK Steel argues that CG&E has failed to provide (a) the amount of its transition revenues; (b) the amount of its transition costs; and (c) proof that its transition revenues equal its transition costs.

AK Steel asserts that, under the stipulation, there is no mechanism to track the RTC revenue recovery and to compare the RTC revenues to the revenue requirement of the allowed regulatory asset transition costs. Thus, AK Steel claims that the RTC recovery will be excessive because it will not terminate once the Company has recovered the allowed costs, but rather will extend for the maximum ten-year RTC recovery period, eight years for residential customers. AK Steel argues that such a result is inconsistent with the statutory requirements. Pursuant to Section 4928.34(12), Revised Code, AK Steel contends that the Company may not recover more than its allowed transition costs.

Shell also takes exception to Ms. Pefley's rebuttal testimony which suggests that, even if purchase power costs are excluded, a $153 million shortfall still exists between CG&E's RTC revenues under the stipulation and its likely transition costs. Shell argues that Ms. Pefley's numbers are unreliable, as they rest on inappropriate assumptions concerning kWh sales levels, market prices, switching rates, and carrying charges. All of these inappropriate assumptions serve either to decrease CG&E's RTC revenues or to increase its RTC costs, thereby producing the revenue "gap" about which Ms. Pefley complains. Shell contends that, when these erroneous premises are corrected, the results strongly suggest that, in fact, CG&E would take in far more in RTC revenues under the stipulation than it would incur in RTC costs.

Shell contends that Ms. Pefley's transition cost figures are still further inflated by the high carrying charge she imputes. CG&E's calculations assume an RTC carrying charge equal to the utility's full authorized pre-tax rate of return of 14.23 percent (Company Ex. 77 Ex. LJP-R-2 at 1 of 5). In light of the non-bypassable, guaranteed nature of RTC collections, Shell states that CG&E does not face the same level of business risk with respect to their collection as applies to other aspects of its regulated business. Additionally, Shell claims that other jurisdictions that have considered this matter have had no difficulty concluding that such transition costs merit a carrying charge closer to the utility's cost of debt than its overall rate of return.

CG&E argues that the rebuttal testimony of Ms. Pefley demonstrates that the Company's recovery of transition costs through the RTC will fall $153 million short of the transition costs that CG&E has shown exist (CG&E Ex. 77 at LJP-R-2 at 1). Further, CG&E points out that the stipulation imposes the risk of a shortfall upon CG&E rather than the consumers. Further, CG&E states that it has used a carrying charge of 14.23 percent because that is the authorized rate of return from its last rate case.

As discussed previously in this order, the Commission finds that existing and new regulatory assets for which the stipulation requests recovery through the RTC are reasonable and do not violate the various provisions of SB3. Although not all of the regulatory transition costs are calculable to the penny at this point in time, Company witness Pefley has provided a reasonable accounting of what the amounts of transition cost are or are projected to become. The stipulation does provide CG&E recovery of previously approved regulatory assets totaling $401 million and new regulatory assets estimated to total at least $483 million (CG&E Ex. 60 at 6-7; CG&E Ex. 50 at Ex. JPS-SUP-5; and CG&E Ex. 77 at Ex. LJP-R-2). It is clear from SB3 that the Commission is authorized to permit the creation of, or amortization of, additional regulatory assets. Therefore, we do not buy into the argument the transition regulatory assets must already be in existence to be prudently incurred (Section 4928.40(A), Revised Code).

Further, Ms Pefley filed rebuttal testimony to support the reasonableness of the amount of transition costs to be recovered through the RTC. Based on a present value of RTC revenue of $517 million, calculated using Mr. Baron's methodology and a pretax authorization rate of return, and comparing it to $552 million of transition costs allowed to be recovered based on the stipulation, not including shopping credit costs, purchased power costs, and appropriate carrying charges, CG&E demonstrates that it is not likely that it will over recover all of its regulatory transition costs through the RTC rider (CG&E Ex. 77 at 4 and 5).

We also note that the Company is only entitled to an opportunity to collect its transition charges and that there is no precise arithmetic guarantee under Section 4928.34(A)(12), Revised Code. Many factors will come into play in the future that will determine whether the Company will under- or overrecover all of its approved transition costs. Consequently, we do not believe that the stipulation is unreasonable or in violation of Section 4928.34(A)(12), Revised Code, because the stipulation does not guarantee that the Company will recover no more than the projected transition costs. With the considerable number of parties that have agreed to the stipulation, the

Commission can conclude that the recovery of transition costs established by the stipulation is reasonable and will not lead to any significant overrecovery of transition costs.

D. Transition Plan Stipulation's Compliance with Sections 4905.33, 4905.35, 4928.37 and 4928.40, Revised Code

As discussed in our summary of the stipulations, the shopping credits for each customer class set forth in the stipulation are higher for the first 20 percent of the load of that customer class that switch to an electric energy marketer. Further, the RTC for residential customers ends at December 31, 2008, as opposed to December 31, 2010, for other customers. The stipulation also provides for a MDP for residential customers of five years while the MDP for other classes could end sooner than five years.

AK Steel contends that these provisions of the stipulation are unreasonable and in violation of Sections 4905.33 and 4905.35, Revised Code. Section 4905.35, Revised Code, provides in relevant part as follows:

> (A) No public utility shall make or give any undue or unreasonable preference or advantage to any person, firm, corporation ...or subject any person, firm, corporation ... to any undue or unreasonable prejudice.

Section 4905.33, Revised Code, provides in relevant part:

> No public utility shall directly or indirectly, or by any special rate, rebate, drawback, or other device or method, charge, demand, collect, or receive from any person, firm, or corporation a greater or lesser compensation for any services rendered, or to be rendered, except as provided in Chapters 4901., 4903., 4905., 4907., 4909., 4921., 4923., and 4925. of the Revised Code, than it charges, demands, collects, or receives from any other person, firm, or corporation for doing a like and contemporaneous service under substantially the same circumstances and conditions.

Objections of AK Steel and Shell

AK Steel states that the shopping credit, although nowhere found in SB3, represents the number, on average, of the cost of power, below which it pays a customer on the Standard Service Offer (SSO) to begin shopping. AK Steel argues that the stipulation's offer of enhanced shopping credits to some customers at the expense of similar customers in similar circumstances is discriminatory. Further, AK Steel contends that the effect is far worse as to non-residential customers, because CG&E may cancel the MDP and, thus, the availability of the SSO as soon as there exists 20 percent shopping by load in a rate class. AK Steel believes that it is to CG&E's distinct economic advantage to cancel the MDP as soon as a class achieves 20 percent load switching even though the remaining 80 percent lose the safe harbor of the SSO. AK Steel contends that significant preference or advantage based upon a place in a queue is unreasonable and unjust and that no rational justification can be found to charge different rates to the same class of customers based on the ability to get into a line first.

AK Steel also argues that CG&E has bestowed upon the residential class benefits that it has not deemed to confer on the non-residential customers. While non-residential customers may be expelled from the SSO whenever the first 20 percent of the customer load of the class switch, the residential customers have the security of the SSO until December 31, 2005. AK Steel believes this is a considerable advantage since it secures them against the vagaries of the market place for five years regardless of whether 20 percent load switching as occurred or not. Further, AK Steel argues that the reduced RTC recovery period for residential customers is discriminatory since it means an underpayment by the residential customers of their share of the RTC.

AK Steel also argues that these provisions concerning shopping credits also violate Sections 4928.37 and 4928.40, Revised Code, because they permit certain customers to by-pass the non-bypassable RTC and create a RTC of less than zero for the first 20 percent of residential customers.

Shell also takes issue with the provision of the stipulation that would permit the Company to end the MDP for non-residential customers prior to December 31, 2005. Specifically, Section 5 of the stipulation would grant CG&E the authority to end the MDP, at its sole option, if (1) 20 percent load switching by class has occurred, (2) CG&E provides notice to the Commission, and (3) CG&E does not have a certified supplier affiliate in its service territory. Shell argues that, because CG&E has indicated it has no intention of establishing a retail marketing affiliate and the notice provision is purely ministerial, CG&E's exercise of this requested discretion would turn on the level of non-residential customer switching. Shell states that, under SB3, a utility's application to end the MDP must demonstrate either that there is 20 percent switching rate by the customer class, or there exists effective competition in the utility's service territory (Section 4928.40 (B) (2), Revised Code). Shell contends that the Commission cannot authorize an early termination to the MDP unless it finds either of the requisite threshold circumstances to exist, something it obviously cannot do now, prior to the commencement of the MDP. Shell argues that the stipulation's request for "up front" authorization to end the MDP seeks to strip the Commission of this flexibility and hand over to CG&E the authority to determine whether circumstances warrant early termination. In Shell's view, the stipulation's proposal concerning early termination of the MDP is unlawful, represents ill-conceived policy, and should be rejected.

Reponses of CG&E and Staff

CG&E disagrees with the arguments made by AK Steel and Shell. The Company asserts that all customers have an equal opportunity to shop and that CG&E exercises no influence over which customers will be among the first 20 percent of load to switch. CG&E also points out that Section 4905.33, Revised Code, recognizes circumstances where preferences may be given pursuant to statutory authority, and Section 4905.35, Revised Code, only prohibits undue or unreasonable preferences. CG&E cites Section 4928.40(A), Revised Code, which permits the Commission to authorize shopping incentives to induce 20 percent switching, to support its argument that the shopping incentives provided are reasonable and permissible by law. With respect to the difference in the MDP and RTC recovery periods among the various classes of customers, CG&E argues that residential customers are not similarly situated to commercial and industrial customers in a competitive context. Further, CG&E points out that any underrecovery of RTC due to the treatment of residential customers within the stipulation is absorbed by CG&E and that CG&E has shown it will underrecover transition costs of approximately $153 million (CG&E Ex. 77 at 2).

CG&E also disagrees that the RTC is being by-passed or is established at below zero. CG&E states that it has shown through the testimony of witness Pefley that all customers pay an undiscounted RTC which is offset by a shopping incentive (CG&E Ex. 65 at Ex. LJP-Sup-8; and CG&E Ex. 77 at LJP-R-2 at 3). CG&E argues that SB3 requires the Commission to consider offsetting the RTC with shopping incentives.

The staff takes the position that shopping incentives are legitimate regulatory tools designed to promote competition. Staff believes that the structure of the shopping credits, MDPs, and the RTC recovery periods are consistent with the regulatory intent of SB3.

Commission Conclusion

The Commission finds that the structure of the shopping credits, MDPs, and the RTC recovery periods do not violate Sections 4905.33 and 4905.35, Revised Code. Clearly, Sections 4928.37(B) and 4928.40(A), Revised Code, provide the Commission with the authority to approve the shopping incentives set forth in the stipulation. Although customers who take the early initiative to shop for an alternative supplier of generation will benefit from their actions, this does not amount to undue preference nor create a case of discrimination. All customers will have an equal opportunity to take advantage of the shopping incentives. The Commission cannot conceive of a mechanism that provides customers with more of an incentive to shop than those created by the stipulation. The Commission also finds that Section 4928.40(A), Revised Code, authorizes the Commission to set the recovery of the costs associated with regulatory assets up to December 31, 2010. The Commission does not find it discriminatory to have two different periods for the recovery of the RTC, one for residential customers and one for non-residential customers, inasmuch as the rates, incentives, and shopping credits vary between the various customer classes.

We also believe that, inasmuch as SB3 permits the Commission to authorize the end of a MDP prior to December 1, 2005 if there is a 20 percent switching rate by a particular class of customer, the approval of such through this order as part of the stipulation is not unreasonable nor contradictory to Section 4928.40(B), Revised Code. Further, we do not believe that the development of a shopping incentive should be viewed as creating an RTC of less than zero or that it permits the RTC to be by-passed. We view the two as separate provisions of the SB3.

E. Shopping Credits

Section 4928.40, Revised Code, provides for the establishment of shopping incentives to induce customers to switch to a certified supplier to obtain their generation supply. The goal of the incentive is to achieve at least a 20 percent switching rate by December 31, 2003. CG&E states that the stipulation creates such shopping incentives by granting shopping credits greater than the projected market price of power. Per the stipulation, such credits are equal to or greater than CG&E's unbundled generation component to the first 20 percent of customers that switch to a certified supplier to obtain their generation supply (CG&E Ex. 60 at 11-14).

Shell argues that the stipulation's shopping credits would not spur the level of switching sought by SB3 and the Commission's rules, particularly among residential ratepayers. Shell's position is that, once a marketer adds on to the wholesale price of power such costs as line loss, advertising, other customer acquisition costs, collection costs, reserves for bad debt, accounts payable, customer call centers, office overheads, and the marketer profit, there will be no margin left to provide the customer a savings off of the $0.05 shopping credit provided the first 20 percent of residential customers who shop. Thus, according to Shell, during the MDPs crucial initial stages, when CG&E's service territory first opens to competition, the stipulation's proposed $0.05 shopping credit would force residential marketers to either offer no significant consumer savings or to do so at a loss. Shell also contends that assuming, for argument's sake, that the initial $0.05 credit did induce a 20 percent residential switch rate by the midpoint of the MDP, the prospect for further customer switching would vanish under the subsequent $0.0394 shopping credit provided the remaining 80 percent of residential customers.

Shell argues that, in short, the fact that the stipulation's proposed shopping credits exceed CG&E's unbundled generation charge has no bearing on whether they merit approval by this Commission. Instead, Shell maintains that the Commission must assess whether those credits would produce the effective competition and competitive choice sought by SB3. Shell claims that CG&E's attempt to mask the deficiency of the stipulation's shopping credits through a simplistic comparison to those offered by Duquesne Light Company misses the mark. Unlike CG&E, Duquesne Light Company did more to promote competition than merely provide shopping credits. Shell believes that CG&E should actually provide a certain amount of generation capacity at a predetermined price to those retail suppliers competing to serve its market.

In conclusion, Shell argues that the stipulation's residential shopping credits are wholly inadequate for accomplishing the level of switching and effective competition sought by SB3 and the Commission should reject them. Alternatively, Shell claims that, if the Commission finds that providing generation capacity is not well suited for the CG&E system, the Commission, at a minimum, should increase substantially the stipulation's residential shopping credits. In this regard, Shell recommends increasing the credit to $0.055 per kWh for the entire MDP. This enhanced initial shopping credit, according to Shell, would have a much greater chance of engendering immediate, vigorous third-party participation in the CG&E residential market than the stipulation's inadequate $0.05 credit.

Shell also takes issue with Section 3 of transition plan stipulation that provides:

> There will be no further netting or adjustments of any kind to CG&E's Transition Cost recovery, including but not limited to any adjustment of RTC rates, or shopping credits through 2010, related to the sale, lease or transfer by CG&E, or any of its affiliates, of any generating assets.

Shell argues that this provision represents a blatant attempt to tie the Commission's hands regarding future actions it might take to protect and encourage the emerging competitive market place in light of unanticipated market conditions. Shell believes that this provision of the stipulation is in conflict with Section 4928.40 (B) (1), Revised Code, which permits the Commission to conduct a periodic review no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility as initially established or subsequently adjusted. Moreover, Shell argues that the Commission is specifically permitted to adjust the regulatory asset component of a utility's regulatory transition charge on a prospective basis after December 31, 2004, or earlier in conjunction with approval of an early termination date for the MDP (Section 4928.39 (D), Revised Code). Shell argues that the acceptance of Section 3 of the stipulation would negate the Commission's broad authority to safeguard retail competition during the MDP and should be rejected.

CG&E's argues that its plan for shopping incentives filed with its transition plan describes numerous studies conducted by CG&E in developing a switching forecast (CG&E Ex. 8 at 2–15; and CG&E Ex. 16 at 6–27). These studies include residential customer satisfaction studies, commercial and industrial satisfaction studies, an image tracking study, and a market forecast study (CG&E Ex. 16 at 6). CG&E contends that an analysis of these studies reveals that, with certified suppliers offering as little as two percent value over CG&E's standard service offer, 22.7 percent of residential load, 52.1 percent of commercial load, 89.5 percent of industrial load, and 69 percent of governmental load are projected to switch to certified suppliers by the end of 2003 (CG&E Ex. 16 at 25, 27). CG&E asserts that these projections far exceed the switching targets specified in Section 4928.40(A), Revised Code. However, CG&E contends that with the stipulated shopping credits, the customers who switch will receive far greater than two percent added value, based on projected retail market prices, and the first 20 percent of the customers who switch will receive even greater incentives.

CG&E also points out that Shell's use of CG&E's wholesale power purchases in 1998 does not reflect properly the wholesale price of power in the future. CG&E asserts that much of this power was purchased during peak periods when prices were high. CG&E argues that it is more appropriate to look forward to projected retail market prices (CG&E Ex. 77 at LJP-R-2 at 4).

The Commission finds that the stipulation provides appropriate shopping incentives to achieve a 20 percent load switching contemplated by Section 4928.40(A), Revised Code. We believe CG&E's forward looking wholesale prices of power used to estimate future retail power markets are more appropriate than CG&E purchased power costs from past years. Further, the record lacks sufficient evidence to support Shell's recommendation of a shopping credit of $0.055 per kWh. The stipulation's $0.05 shopping credit for the first 20 percent of residential customer load that switches exceeds the unbundled rate for generation and, therefore, should help ensure that residential customers have an incentive to shop. The first 20 percent load switched from the remaining customer classes will also have an adequate incentive to shop inasmuch as shopping credits will equal 100 percent of the unbundled generation rate. We believe that these significant shopping incentives will effectively foster early competition by providing significant motivation to customers to switch retail generation suppliers.

With regard to Section 3 of the stipulation, the Commission does not believe that this provision is in conflict with Section 4928.40(B)(1), Revised Code. This section of the Revised Code permits the Commission to conduct a periodic review no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility as initially established or subsequently adjusted. It does not require such reviews or adjustments. We believe that the stipulation establishes reasonable transition charges, shopping credits, and incentives for customers to shop. We do not believe that Section 3 negates the Commission's broad authority to safeguard retail competition during the MDP. Various sections of SB3 give the Commission the continued oversight to monitor the progress of competitive retail electric services, to take action where necessary, and to promote the policies of the state of Ohio set forth in Section 4928.02, Revised Code.

F. CG&E's Corporate Separation Plan (CSP)

CG&E proposed a CSP that it contends meets all the requirements set forth in Sections 4928.17 and 4928.06, Revised Code, and the Commission's rules on utilities' code of conduct. No parties opposed CG&E's CSP. Under its plan, effective January 1, 2001, CG&E will not offer non-tariffed products and services and it will transfer any such products and services to a fully separated affiliate (CG&E Ex. 57 at 2). Additionally, CG&E's CSP provides for the transfer of its generating assets to an EWG and, according to the plan, CG&E will complete the transfer by no later than December 31, 2004 (CG&E Ex. 57 at 3). CG&E's CSP also describes the mechanisms that CG&E will utilize to ensure that CG&E institutes proper accounting procedures for affiliate transactions (CG&E Ex. 57 at 4-5). CG&E's CSP includes provisions related to structural safeguards, separate accounting, financial arrangements, complaint procedures, education and training, the policy statement, internal compliance monitoring, and a detailed listing of CG&E's electric services. As described in the testimony of Paul G. Smith, CG&E will implement a cost allocation manual, pursuant to Rules 4901:1-20-16(G)(1)(a) and (b) and 4901:1-20-16(J), O.A.C. (CG&E Ex. 14 at 5). CG&E will also only share employees, facilities, and services in accordance with its SEC-approved service agreements, pursuant to Rule 4901:1-20-16(G)(1)(c), O.A.C. (CG&E Ex. 37 at 3). Under its proposal, CG&E will keep its books, records, and accounts separate from those of its affiliates pursuant to Rule 4901:1-20-16(G)(2), O.A.C. (CG&E Ex. 14 at 6). CG&E will also follow the Commission's rules on financial arrangements to preserve the financial independence of CG&E from its affiliates pursuant to Rule 4901:1-20-16(G)(3), O.A.C. (CG&E Ex. 14 at 7).

CG&E's filing includes an affiliate code of conduct that complies with the Commission's rules. According to the Company's proposal, CG&E is prohibited from releasing any proprietary customer information to an affiliate without the prior authorization of the customer (CG&E Ex. 37 at Ex. PGS-1 at 2). Furthermore, CG&E's affiliate code of conduct requires CG&E to make customer lists available on a nondiscriminatory basis to all nonaffiliated and affiliated certified retail electric competitors transacting business in its service territory (*Id.* at 1). CG&E's affiliate code of conduct stipulates that the Company shall treat as confidential all information obtained from any certified supplier of retail electric service and that the Company shall not tie the provision of regulated services to the taking of any goods and/or services from CG&E's affiliates. CG&E maintains that its code of conduct ensures that anticompetitive subsidies will not flow from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa (*Id.* at 6).

CG&E notes that Section 4928.17(C), Revised Code, provides that "for good cause, the Commission may issue an order approving a corporate separation plan that does not comply with Section 4928.17(A)(1), Revised Code, but complies with such *functional separation requirements* as the Commission authorizes to apply for an interim period. Further, CG&E states that the Commission's corporate separation rules require the utility to show good cause for selecting an interim functional separation plan. CG&E believes that it has met this burden through its corporate separation financing plan. CG&E notes that its corporate separation financing plan provides for a program to complete the transfer of its generating assets to an EWG by December 31, 2004, and it describes the expected costs CG&E would incur if it is forced to transfer its generating assets to the EWG by December 31, 2000. It is CG&E's intention to achieve the transfer of assets to the EWG at the lowest cost practicable by seeking to minimize the transaction costs, including tax obligations; minimize the expenditures related to the recapitalization of CG&E; and optimize the capital structure of CG&E. CG&E's ability to minimize its transaction costs will turn on three key issues: (1) what steps CG&E must take to adjust its capital structure as a result of the corporate separation plan; (2) whether it can release the generation from the mortgage without having to redeem the first mortgage bonds; and (3) whether it can eliminate or minimize the tax obligations which may arise from the transfer (*Id.* at 3). CG&E is undertaking the process of seeking to release the generation assets from its existing first mortgage lien obligations (*Id.* at 3). CG&E expects this process to take at least six to nine months (*Id.* at 3). While CG&E hopes that it can achieve this release, there can be no assurance that CG&E will be fully successful. In the event CG&E is unsuccessful, it may have to pursue other means to release the properties, as described in CG&E's Corporate Separation Financing Plan.

CG&E has presented a corporate separation plan for Commission approval pursuant to Section 4928.17(C), Revised Code. CG&E has indicated that, if it is forced to transfer its generating assets to the EWG by December 31, 2000, it will incur significant costs. Since the corporate separation plan does not provide for complete separation by December 31, 2000, in order for this Commission to approve an interim plan the company must show "good cause" pursuant to Section 4928.17(C), Revised Code. This section provides that an interim plan must be consistent with such functional separation requirements as is authorized for the interim period, and that the plan must provide for ongoing compliance with the policy set out in Section 4928.02, Revised Code. Section 4928.17(A)(2), Revised Code, also requires that all plans satisfy the public interest in preventing unfair competitive advantage and abuse of market power. The plan must also be sufficient to ensure that no undue preference or advantage is extended to or received by the competitive retail affiliate from the utility affiliate (Section 4928(A)(3), Revised Code). The Commission's rules also address interim plans and require that such plans set out a detailed timeline of progression to full structural separation, and that they be subject to periodic Commission review (Rule 4901:1-20-16(G)(1)(d), O.A.C.).

We find that CG&E's proposed interim plan achieves the structural separation contemplated by Section 4928.17(A)(1), Revised Code, and the corresponding Commission rules. The Company has shown that it will incur significant costs if it is forced to transfer its generating assets to the EWG by December 31, 2000. We find that good cause exists to allow the separation as proposed by the company to occur by December 31, 2004, in that specific steps are set forth to insure the release of the subject properties in that time frame. The plan provides for competitive retail electric service through a fully separated affiliate of the utility and includes separate accounting requirements and code of conduct necessary to effectuate the policy specified in Section 4928.02, Revised Code. The plan also satisfies the public interest in preventing unfair competitive advantage and preventing the abuse of market power. The plan also is sufficient to ensure that the Company will not extend any undue reference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric produce or service. CG&E has provided a reasonable timeline for its transition to full structural separation. Therefore, the Company has met its burden of showing "good cause" for this Commission to approve the interim functional separation plan. We will closely monitor the implementation of the plan and take appropriate steps where we find competitive inequality, unfair competitive advantage, or abuse of market power. We believe that through the periodic Commission review of the interim separation plan, through auditing of the company's books and records, including the cost allocation manual, and the complaint process, this Commission can ensure that the corporate separation plan is implemented in accordance with the policy enunciated in SB3.

G. <u>CG&E's Employee Assistance Plan (EAP)</u>

CG&E's EAP was presented through the testimony of Richard L. Bond, CG&E's general manager of Compensation, Benefits and Human Resources Information System. Mr. Bond described CG&E's EAP including the programs for severance, retraining, retirement, retention, outplacement and other assistance that the company commits to provide to its employees whose employment is affected by electric industry restructuring (CG&E Ex. 17, 3). Mr. Bond contended that CG&E's EAP provides for all of the types of benefits described in Section 4928.31(A)(4), Revised Code, and that the EAP will be communicated to CG&E's eligible employees verbally and in writing (*Id.* at 3). He noted that CG&E has had experience with voluntary workforce reduction and voluntary severance plans and that a very substantial number of those employees who were eligible to participate in the plans took advantage of the plans' benefits (*Id.* at 5). Mr. Bond also testified that CG&E has no current plans to downsize its workforce during the MDP as a result of restructuring (*Id.* at 6). CG&E has requested no transition costs related to the EAP (CG&E Ex. 12 at Ex. JPS-5 at 1). No parties opposed CG&E's EAP or the EAP stipulation.

Pursuant to Section 4928.34(A)(10), Revised Code, the Commission finds that the Company's EAP sufficiently provides severance, retraining, early retirement, retention, outplacement, and other assistance for the Company's employees whose employment is affected by electric industry restructuring. As noted above, CG&E's EAP will be subject to negotiations with CG&E's unions and, in accordance with the EAP rules, we will continue to provide the Company flexibility in implementing the EAP.

H. CG&E's Education Plan

Section 4928.31(A)(5), Revised Code, requires each utility's transition plan to include a consumer education plan consistent with Section 4928.42, Revised Code. Section 4928.42, Revised Code, provides that, prior to the starting date of competitive retail electric service, the Commission shall prescribe and adopt a general plan by which each electric utility shall provide during its MDP consumer education on electric restructuring. Utilities are required to spend up to $16 million in the first year on consumer education within their certified service territories and an additional $17 million in decreasing amounts over the remaining years of the MDP. As part of its transition plan, CG&E filed an education plan, which was later amended. CG&E's amended education plan targets residential customers; small and mid-sized commercial customers; elected officials, community leaders, civic organizations, trade associations, and consumer groups; and large commercial and industrial customers. The amended plan also describes the methods, timelines, and spending that will be used for CG&E's education campaign. Further, CG&E's amended education plan included deferral of its expenditures on consumer education in CG&E's requested transition costs recovery. No parties opposed CG&E's amended education plan.

On November 30, 1999, the Commission issued rules for the electric transition plan proceedings, and adopted a general plan for electric utilities' consumer education in Case No. 99-1141-EL-ORD, *In the Matter of the Commission's Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Revised Code*. After the companies filed their transition plans, various intervenors filed preliminary objections. Separate staff reports were filed in each of the transition plan proceedings. In each staff report, the staff stated that the consumer education plans are consistent with the requirements issued by the Commission on November 30, 1999.[8] After reviewing all of the education plans filed in all of the transition cases and after considering the objections and comments submitted, we found in our July 20, 2000 finding and order in 99-1658-EL-ETP et al., CG&E's amended education plan to be in compliance with Section 4928.42, Revised Code, and we approved CG&E's education plan subject to three contingencies. First, we noted that, with regard to provisions for the funding of local community-based organizations (CBO), although we did not require funding of the CBOs, we did encourage CG&E to provide CBO funding. We also required CG&E to include an unaffiliated energy marketer representative on their advisory groups. Second, we required that the plans for CG&E include further details on how the territory-specific campaigns will be managed and operated, how materials and information will be disseminated, and how funds will be allocated to activities, as well as other matters. Further, we conditioned our approval on the Commission staff's continuing supervision of the general and territory-specific plans as further details are developed for each of the consumer education programs. With the

8 The staff's only recommendation was the inclusion of an energy marketer representative in the advisory group. CG&E was the only company to file an amended education plan that added an energy marketer representative to the advisory group.

conditions to CG&E's education plan set forth in our July 20, 2000 order, we find that CG&E's transition plan complies with Section 4928.31(A)(5), Revised Code.

I. Independent Transmission Plan (ITP)

Pursuant to Section 4928.12(A), Revised Code, no entity shall own or control transmission facilities (as defined by federal law) in Ohio as of the date of competitive retail electric service unless the entity is a member of, and transfers control of those facilities to, one or more qualifying transmission entities. Section 4928.12(B), Revised Code, sets forth nine requirements for a qualifying transmission entity must meet including: (1) the transmission entity is approved by FERC; (2) the transmission entity separates control of transmission facilities from control of generation facilities; (3) the transmission entity implements, to the extent reasonably possible, policies and procedures designed to minimize pancaked transmission rates within Ohio; (4) the transmission entity improves service reliability within Ohio; (5) the transmission entity provides for an open and competitive electric generation marketplace, eliminates barriers to market entry and precludes control of bottlenecked transmission facilities; (6) the transmission entity is of sufficient scope or otherwise increases economical supply options; (7) the transmission entity's governance structure is independent from transmission users; (8) the transmission entity satisfies customers' electricity requirements; and (9) the transmission entity maintains real-time reliability of the transmission system, ensures comparable and non-discriminatory transmission access and necessary services, minimizes congestion and addresses transmission constraints. CG&E states that the requirements of Section 4928.12(B), Revised Code, are substantially similar to the requirements established by the FERC for Independent System Operators (ISOs) in Order No.888[9] and for Regional Transmission Organizations (RTOs) in Order No. 2000.[10] CG&E asserts that an RTO approved under FERC's Order No. 2000 requirements will of necessity also satisfy the requirements of Section 4928.12(B), Revised Code.

CG&E witness John C. Procario (CG&E Exs. 20 and 54) sponsored and explained CG&E's ITP, which is Part G of CG&E's transition plan. Mr. Procario explained how CG&E believes the MISO and CG&E's participation in the MISO satisfies each of the requirements of Section 4928.12(B), Revised Code, as well as the more specific criteria set forth in Rule 4901:1-20-17, O.A.C. Mr. Procario indicated that CG&E will belong to the MISO and that the MISO is a transmission entity approved by FERC. He noted that FERC initially gave conditional approval to the MISO on September 16, 1998 (CG&E Ex. 20 at 9). The MISO transmission owners subsequently made a compliance filing and FERC issued an order approving the compliance filing on April 16, 1999, conditioned on a minor change that the MISO Transmission Owners made on May 17, 1999 (CG&E

---

9 FERC Stats. & Regs., ¶ 31,036 (1996)

10 FERC Stats. & Regs. ¶ 31,089 (2000).

Ex. 20 at 9-10). He indicated that the MISO still must make additional compliance filings within 60 days of becoming operational regarding filing and operating procedures and the MISO must also make a compliance filing arising from FERC's recent Order 2000 (CG&E Ex. 20 at 9; 89 FERC Section 61,285; Buckeye Ex. 2 at 22).

Mr. Procario indicated that the MISO will separate control of transmission facilities from control of generation facilities because the MISO will have functional control over transmission facilities (CG&E Ex. 20 at 14-15). Mr. Procario testified that the MISO also eliminates pancaked transmission rates within the MISO, by providing for non-pancaked zonal rates during a six-year transition period (CG&E Ex. 20 at 20). At the end of the six-year transition period, the progression to a single rate or combined rates will depend on how quickly states encompassed by the MISO adopt customer choice and the development of independent transmission companies (*Id.* at 22). Under the ITP stipulation, CG&E committed to participate in the collaborative process under FERC Order 2000 to discuss integrating the facilities of the transmission-owning utilities in Ohio. CG&E will also seek to enter into a joint stipulation with all of the other transmission-owning utilities in Ohio to submit the subject of how to achieve the objectives listed in Rule 4901:1-20-17(B)(3), O.A.C., and related issues to a separate joint Commission hearing dealing solely with that subject as part of their respective transition plan application proceedings. CG&E will also seek to jointly request, together with the intervenors in this case, that the Commission order the other transmission-owning utilities to participate in such a hearing. CG&E will also participate in a statewide collaborative process to resolve the transmission seams issues in Ohio.

Mr. Procario noted that the MISO improves service reliability within Ohio because the MISO will act as the security coordinator for the transmission facilities under its functional control (CG&E Ex. 20 at 24). In addition, the MISO will promote open competition because the MISO's transmission usage and availability will be publicly posted on OASIS in real time and the MISO's transmission rates will be calculated in a uniform manner and will also be publicly available (*Id.* at 29). Mr. Procario indicated that the MISO is of adequate size and scope to increase economical supply options. He noted that the MISO's scope and configuration is significant because the MISO would serve a 16-state area and span three reliability councils: MAIN, ECAR, and MAPP (CG&E Ex. 20 at 7). Mr. Procario also testified that the MISO has several structural features that provide for independent governance. The MISO's governing structure consists of an independent board of directors and an advisory committee. Any eligible transmission customer may join the MISO. The members elect the board of directors (CG&E Ex. 20 at 36, 37). The MISO provides for satisfaction of customer requirements because it provides non-discriminatory open access to the transmission system for all eligible transmission customers (CG&E Ex. 20 at 44). Finally, Mr. Procario noted that the MISO will provide for real-time reliability because it will have primary responsibility for short-term reliability of the grid's operation (CG&E Ex. 20 at 48).

We note that the transition plan stipulation and the ITP stipulation are designed to address the fact that, even if the MISO is fully approved by FERC by January 1, 2001, it will not be operational until some time later that year. The MISO is currently scheduled to become operational during 2001 (CG&E Ex. 20 at 10). CG&E respectfully requests that the Commission approve a deferral of CG&E's compliance with the ITP requirements until December 31, 2001, as the Commission is expressly authorized to do under Sections 4928.34(A)(13) and 4928.35(G), Revised Code.

Objections to CG&E's ITP

Buckeye, a non-profit electric generation and transmission cooperative, and OREC, a statewide association that represents the interests of Buckeye and its members, argue that CG&E's transition plan fails to meet the requirements of Section 4928. 12(B), Revised Code, because it fails to satisfy the requirement to minimize pancaked transmission rates in Ohio[11]. Buckeye and OREC contend that rate pancaking is a major obstacle to the development of workably competitive markets for electric generation service. According to Buckeye and OREC, CG&E has three options under SB3 to minimize transmission rate pancaking by January 1, 2001. In this case, Buckeye and OREC argue that CG&E has failed to make an adequate proposal in its transition plan under any of these three criteria to minimize pancaking and, therefore, its transition plan should be rejected (*Id.* at 6).

Buckeye and OREC contend that, under the first option, utilities can all be part of one transmission entity. Buckeye notes that CG&E is a member of the MISO, while three of the other four investor-owned utilities in Ohio, American Electric Power Company ("AEP"), FirstEnergy Corporation ("FirstEnergy"), and Dayton Power and Light Company ("DP&L"), plan to be members of the Alliance RTO. Buckeye and OREC agree that a merger of these two entities would maximize the reliability benefits and enhance competition. However, they claim that CG&E participated in discussions about merging the Midwest ISO and the Alliance RTO, but those discussions have been unsuccessful. Thus, Buckeye and OREC contend that, so long as CG&E remains in the MISO, and AEP, FirstEnergy, and DP&L are in the Alliance RTO, there will be a transmission "seam" in Ohio, and the requirement to minimize transmission rate pancaking will not be met. Under the second option, CG&E can enter into reciprocity agreements with other Ohio utilities to minimize pancaking of rates. Mr. Solomon explained in his direct testimony how such reciprocity agreements are established. Buckeye and OREC state, however, that CG&E acknowledged that it has never provided a reciprocity proposal for the other Ohio utilities to consider. Mr. Solomon argued that the failure of the MISO and the Alliance RTO to reach agreement on merging into a single RTO could result in the creation of at least two RTOs that would operate within Ohio (*Id.* at 7). The third option allows utilities to propose another means

11 Rate pancaking occurs when each owner of a transmission system is allowed to add the transmission price to the cost of delivering energy.

to minimize rate pancaking. According to Buckeye and OREC, CG&E claims it is satisfying the third criteria because, under the stipulation, it is agreeing to participate in the collaborative process under FERC to resolve the transmission seams issues, and to participate in hearings at the Commission if other transmission owning utilities will not agree to work together (*Id.* at 18). Buckeye and OREC argue that, under this option, the utility must provide documentation to enable the Commission to determine whether it has met its burden (*Id.* at 19). They argue that CG&E has failed to provide documentation that would demonstrate that the MISO will minimize pancaked transmission rates. Further, Mr. Solomon contends that CG&E's ITP is only a promise to continue talking about pancaking and, therefore, CG&E's transition plan should be rejected.

Commission Conclusion

Pursuant to Section 4928.34(A)(13), Revised Code, as an alternative to approving an ITP that complies with Section 4928.12, Revised Code, the Commission may, for good cause shown, authorize a company "to defer compliance until an order is issued under division (G) of Section 4928.35 of the Revised Code." Upon review, we find that we will defer approval of CG&E's ITP. Our action is based, in part, because the Commission cannot determine, at this time, whether the Midwest ISO, in its present state, is compliant with the requirements of Section 4928.12, Revised Code. At this time, the MISO is not operational and is not projected to be operational until late 2001. Furthermore, CG&E's ITP does not, at this time, minimize pancaked transmission rates and there are no provisions in the stipulation that act to minimize pancaked transmission rates during the interim time period until the Midwest ISO is operational. We note that, under the stipulation in FirstEnergy Corp. (99-1212-EL-ETP et. al.,) the FirstEnergy Corp. operating companies agreed to reimburse any supplier serving retail customers within the operating companies' respective service areas for the cost of any associated transmission charges imposed by the Pennsylvania-New Jersey-Maryland Interconnect and/or by the Midwest ISO. No such provisions exist under the CG&E stipulation. Accordingly, for these reasons, the Commission will defer the approval of CG&E's ITP until such time as the activities set forth in paragraph 5 of the ITP stipulation have been explored to adequately address compliance with Section 4928.12, Revised Code, and Rule 4901:10-20-17(B)(3), O.A.C., regarding minimizing pancaked transmission rates. We will authorize CG&E to defer compliance with these provisions until an order is issued pursuant to Section 4928.34(A)(13), Revised Code.

J. Exempt Wholesale Generator (EWG)

Under section 8 of the transition plan stipulation, CG&E's EWG will be prohibited from selling power to an affiliate for resale at retail in CG&E's service territory, except through CG&E's RCSA, and it will be prohibited from selling to an affiliate certified supplier on more favorable prices or terms than CG&E sells to a non-affiliate certified supplier. The information regarding the sales or transfers of power and ancillary services by the EWG to an affiliate shall be simultaneously posted with the execution of any agreement for the sale or transfer on a publicly available electronic bulletin board.

Shell objects to CG&E's treatment of the wholesale power price it would pay to the EWG. Shell claims that, by shielding the price paid to the EWG for the wholesale power resold as standard offer service, stipulation Section 8 would deprive the market place of pricing transparency regarding the EWG's dealings with an affiliate that likely would be its single largest customer during the MDP. Shell also contends that it would make it more difficult for competitors to discern anticompetitive price discrimination in favor of standard offer service. Shell argues that, even if a supplier did not purchase power from the EWG, the pricing information at issue would represent a significant part of the prevailing wholesale market, and would assist suppliers in assessing prices available from alternative wholesale power sources. According to Shell, withholding the EWG's standard offer-related pricing thus would distort the wholesale market pricing signals received by third-party suppliers, thereby producing uneconomic wholesale deals that, in turn, would make it more difficult for marketers to offer significantly lower prices to consumers. Shell contends that access to the wholesale prices paid the EWG by CG&E also would permit third parties and the Commission to monitor the excess generation revenues collected by CG&E under its frozen rate for standard offer generation service.

CG&E claims that Shell's first contention is wrong. It maintains that, under CG&E's RCSA, the price to be paid by CG&E to the EWG is set at the unbundled generation rate charged to CG&E's customers who have not switched and that these unbundled rates are delineated in CG&E's filed tariffs. Thus, the price charged by the EWG to CG&E is information available in public documents and simply not shielded. CG&E also finds Shell's arguments regarding suppliers purchasing power from the EWG as not credible. CG&E maintains that its RCSA sets the price to be paid by CG&E at the unbundled generation rate charged to CG&E's customers who have not switched and that these generation rates are set forth in its filed tariffs. CG&E also contends that it is required to report monthly data related to noncompetitive electric generation services to the Commission on a quarterly basis. It contends that this information is all that is needed to monitor CG&E's generation revenues. CG&E also argues that to allow suppliers to purchase power from the EWG at unbundled generation standard service offer rates would provide nothing more that a subsidy to CRES providers and should be rejected.

Upon review of the issues raised by Shell, we find that stipulation Section 8 to be reasonable. We agree with CG&E that, according to the stipulation, the price to be paid by CG&E to the EWG under CG&E's RCSA will be set at the unbundled generation rate charged to CG&E's customers who have not switched. This information will be available in CG&E's filed tariffs and will not be shielded. We also agree with CG&E on Shell's second argument regarding access to sufficient information in order to monitor CG&E's generation-related revenue. We believe that the rate information set forth in CG&E's tariffs in conjunction with CG&E's reporting data on sales, billed revenues, and other monthly data will provide sufficient information in order to monitor CG&E's generation revenues. Finally, with regard to the issue of allowing suppliers, such as Shell, to purchase power from the EWG at unbundled generation standard service offer rates, the Commission finds that the stipulation provides adequate measures to promote competition and, therefore, does not believe it is necessary to mandate at what price suppliers can purchase power from the EWG.

IV. CRITERIA FOR EVALUATING STIPULATIONS

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See, Consumers Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, at 125, *citing Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Ohio-American Water Co.*, Case No. 99-1038-WW-AIR (June 29, 2000); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1004); *Ohio Edison Co.*, Case No. 91-698-EL-FOR et al. (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreements, which embody considerable time and effort by the signatory parties, are reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 547 *(citing Consumers' Counsel, supra*, at 126). The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission *(Id.)*.

Based on our three-prong standard of review, we find that the first criterion, that the process involved serious bargaining by knowledgeable, capable parties, is met. Multiple bargaining sessions, open to all parties, took place before commencement of the hearings. The parties to these negotiations have been involved in many cases before the Commission, including a number of prior cases involving rate issues. Further, there have been few settlements in major cases before this Commission in which the overwhelming majority of intervenors either supported or do not oppose the resolution of issues presented by the stipulations.

The stipulations also meet the second criterion. The stipulated resolution of these cases is for many reasons advantageous and promotes the public interest. The stipulations establish a framework for transition to and development of a competitive electricity marketplace in an orderly fashion. The stipulations also remove significant uncertainty and continuing controversy which could delay the primary goal of these proceedings to create a functioning and effective retail market for the sale of electricity to CG&E customers and an orderly transition from the traditional regulatory environment to one of supplier and service choices. Further, the stipulations assure an aggressive transition to a functioning retail generation market and provides other significant economic benefits for consumers, some of which would otherwise have been subject to legal challenge by CG&E. These benefits take the form of extended rate freezes, rate reductions, flexibility for larger contract customers not otherwise available, low income energy efficiency grants and, as a result of shorter, defined transition periods for CG&E, significant risks with respect to its ability to recover transition costs. Additionally, through the availability of shopping credits and incentives, the stipulations enable marketers to compete and sell retail electricity. Some of these benefits include:

(1) Offers a five percent reduction of CG&E's generation component, including RTC, for residential rate schedules

(2) Creates shopping credits that facilitate the development of the retail marketplace.

(3) Waives the switching fee for the first 20 percent of residential customers that switch to a certified supplier during the MDP.

(4) Maintains for five years the MDP, including a rate cap, to the residential customers, irrespective of the number that switch.

(5) Continues support for energy efficiency and weatherization services to low-income persons by maintaining certain existing contracts valued at approximately $4 million for five years.

(6) Prohibits the Company's EWG from offering power or ancillary services incident to the delivery of power at prices and terms more favorable than those available to the non-affiliated electric suppliers.

(7) Offers to customers with contracts approved pursuant to Section 4905.31, Revised Code, who would otherwise be on the primary distribution, transmission, or lighting rate schedules, a one-time right, through December 31, 2001, to cancel any such contract without penalty, provided that the customer remains a distribution customer of CG&E.

(8) CG&E offers to make best efforts to implement consolidated bill-ready billing by January 1, 2002, and to implement supplier consolidated billing by June 1, 2002.

(9) CG&E commits to work with other regions, RTO/ISO groups and transmission level customers to develop and implement specific proposals to address reciprocity and interface/seams issues.

(10) CG&E commits to accept any resolution of issues agreed to by all OSPO working-group participants and to incorporate any such changes in its transition plan.

(11) CG&E offers to amend its OATT to add a new schedule for retail energy imbalance service, and will amend its OATT to allow transmission customers to designate new resources on a day-ahead basis, provided that there exists available transfer capacity that is subject to the approval of the transmission provider, and that the transmission customer relinquishes network transmission rights to a designated resource once a new resource is designated.

(12) CG&E offers to establish a technical task force to address and attempt to resolve technical and operational issues that may arise upon implementation of customer choice.

Adoption of the stipulations also reduces significantly the number of possible appeals, and provides additional lead time to put in place the mechanisms necessary to get the customer choice program up and running. Additional evidence that the public interest is served by the stipulations is found in the support offered by representatives of residential, commercial, and industrial customers, including OCC and the Commission's staff. As indicated above, the agreement provides that certain rates will be decreased and the prior rate plan freezes extended.

Finally, the stipulations meet the third criterion because they do not violate any important regulatory principle or practice. Indeed, the agreements balance the interests of a broad range of parties that represent a diverse spectrum of views. As indicated in the description of stipulations provided above, the stipulations provide substantial benefits to all customer classes and shareholders. Further, the policies of the state embodied in SB3 will be implemented more quickly and efficiently than would otherwise be possible.

V. PENDING MOTIONS

A. Interlocutory Appeal of Examiner's Ruling

On May 15, 2000, AK Steel filed a motion to compel discovery against CG&E to name and produce for deposition and other discovery all persons who have knowledge of any agreements, promises, payments, or inducements offered to any of the signatories to the transition plan stipulation filed in this case. Further, AK Steel requested that each such person be required to produce all letters, notes, agreements, tapes, and contracts discussing, proposing, promising, or agreeing to some inducement to a signatory. AK Steel argued that, according to the language in the stipulation, the stipulation and CG&E's filing in this case represent all of the facts and data upon which the signatories relied when agreeing to the stipulation. AK Steel contended that it has reason to believe that some or all of these assertions are untrue and it seeks to confirm or disprove its suspicion. AK Steel claimed that, if it were shown that some or all of the signatory parties to the stipulation were offered or promised special consideration in addition to the terms of the stipulation, it would impeach or contradict the fundamental assertions of the stipulation. AK Steel cited to Rule 4901-1-16(B), O.A.C., that provides that any party to a Commission proceeding may obtain discovery of any matter, not privileged, which is relevant to the subject matter of the proceeding. AK Steel argued that an intervenor inquiring into the reasonableness of a stipulation should not be prevented from discovering the motives and considerations provided to those who signed and supported the stipulation.

Also on May 15, 2000, CG&E filed a memorandum in opposition to AK Steel's motion to compel discovery. CG&E contended that AK Steel's motion is in direct conflict with the policy of the Commission to encourage settlement and is irrelevant to the proceeding. CG&E argued that the stipulation is a recommendation that is not legally binding upon the Commission. CG&E contended that the Commission must conclude independently that, based on the evidence, the stipulation offers a just and reasonable resolution of the issues. CG&E claimed that the motives of the parties who signed the stipulation are irrelevant to the determination of the Commission's approval of the stipulation. CG&E also contended that the only result of an inquiry into any alleged side agreements among the parties could only be to approve or disapprove such alleged agreements, which is not relevant to the stipulation. CG&E also contended that public policy favors the compromise and settlement of disputes and the Commission recognizes the need to encourage settlement among parties.

The examiners assigned to this case issued an entry on May 19, 2000 ruling that AK Steel's motion should be denied. The examiners found that AK Steel failed to state what relevance the information it might discover through its motion to compel could have on the Commission's determination in this case. The examiners stated that the stipulations in these cases address the rates and services proposed in CG&E's transition plan and that the Commission's charge will be to determine if the stipulations and CG&E's transition plan are just and reasonable. The examiners also stated that motives of the parties in agreeing or not agreeing to sign the stipulation should not and will not affect the Commission's determination of the reasonableness of the stipulations and CG&E's transition plan. Consequently, the examiners believed that the discovery request of AK Steel was not relevant to the subject matter of the proceeding. The examiners further noted that evidence of the motives of parties in signing a stipulation is generally not admissible in a hearing.

On May 24, 2000, AK Steel filed an application for review and interlocutory appeal of the hearing examiners' May 19, 2000 discovery ruling. AK Steel argues that it was improper for the examiners to deny its motion to compel. AK Steel argues that the evidence adduced from the discovery would be relevant to whether the stipulations are discriminatory on their face and not in the public interest if it can be shown that CG&E has agreed to give special considerations to parties that signed on to the stipulations. AK Steel reiterates many of the same argument raised in its original motion to compel. On May 25, 2000, CG&E filed a memorandum in opposition to AK Steel's application for review.

Inasmuch as AK Steel's application for review has not been addressed prior to the issuance of this opinion and order, the Commission will address it at this time. The Commission affirms the ruling of the examiners for the reasons set forth in the examiner's May 19, 2000 entry. The Commission agrees that the information AK Steel seeks to discover will not lead to relevant information. The Commission will determine if the stipulation and CG&E's transition plan are just and reasonable. The transition plan and stipulation can not be modified by any private agreements not before the Commission. The motives of the parties in agreeing or not agreeing to sign the stipulation will not affect the Commission's determination of the reasonableness of the stipulation and CG&E's transition plan. Further, as noted by the examiners, the Commission's longstanding policy has been to encourage settlements in cases that come before it. The Commission believes that its policy would not be advanced if one party in a case could require another party to disclose information on the motives toward settlement or force another party to produce all letters, notes, agreements, tapes, and contracts related to that settlement motivation. By granting AK Steel's motion, we would be forcing such disclosures.

Further, the Commission has the authority to verify CG&E's compliance with SB3, Title 49 of the Revised Code, and the Commission's rules, including the corporate separation requirements of the Commission's order and CG&E's corporate separation plan and applicable code of conduct. In addition, the Commission has authority to audit any transactions made by CG&E and its affiliates. This authority allows the Commission to prevent any improper subsidy or discriminatory treatment of customers. Accordingly, AK Steel's request that the Commission overturn the examiners' decision is denied.

B. Filing of Compliance Tariffs

On June 27, 2000, the CCE filed a motion for a "compliance tariff filing, service, review, and comment procedures.[12]" The motion states that, because of the broad-sweeping changes that will be subject to the provisions of the tariffs ultimately approved in these proceedings, it is necessary to allow interested parties adequate time to review and comment on the proposed tariffs prior to final approval. CCE requests that the Commission order each of the applicants in the transition plan cases to serve tariffs and associated work papers simultaneous with their filing with the Commission. CCE asks that a two-week period be provided after the date of receipt of the tariffs and work papers in order for intervenors to review the documents and submit comments to the Commission for its consideration prior to approval of the tariffs.

CCE's motion shall be granted, subject to modification. We believe that, instead of receiving formal filings with respect to CG&E's compliance tariffs, a more informal process will be beneficial to all interested parties. Accordingly, the Company and other interested parties should observe the following timelines for distributing and reviewing CG&E's proposed tariffs pursuant to this order: (1) within 14 days following the issuance of this order, CG&E should distribute (via electronic mail, fax, or overnight delivery) to all intervenors and the Commission's staff a working draft of its proposed compliance tariffs as well as associated work papers, and UNB schedules that reflect the rates embodied in the compliance tariffs; (2) within 14 days thereafter, interested parties should circulate (via electronic mail, fax, or overnight delivery) comments to the Company and the staff regarding the Company's working draft[13]; and (3) within 14 days thereafter, CG&E shall formally file its proposed tariffs in the form of an application for approval of compliance tariffs.

---

12 This motion was jointly filed in all of the pending electric transition plan dockets.

13 Neither the working draft nor the informal comments are to be filed formally in the docket in this proceeding.

VI. FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) On December 28, 1999, CG&E filed its transition plan, appendices, schedules, testimony, and supplemental information.

(2) Preliminary objections were filed between January 26, 2000, and February 14, 2000.

(3) On March 27, 2000, the Staff Report was filed. CG&E filed supplemental testimony on May 1, 3, and 17, 2000, and rebuttal testimony on June 12, 2000.

(4) Intervention was granted to a number of parties. On May 8, 2000, a stipulation and recommendation on CG&E's transition plan was filed by CG&E; the staff; Ohio Consumers' Council; Ohio Council of Retail Merchants; Industrial Energy Users-Ohio; Kroger Company; The Ohio Manufacturers' Association; National Energy Marketers Association; New Energy Midwest, LLC; WPS Energy; Enron Energy Services, Inc.; Dynegy, Inc.; Cincinnati/Hamilton County Community Action Agency; Supporting Council of Preventive Effort; The Ohio Hospital Association; ODOD; People Working Cooperatively; Exelon Energy; Strategic Energy; Columbia Energy Services Corp.; Columbia Energy Power Marketing Corp.; Mid-Atlantic Power Supply; city of Cleveland; and American Municipal Power-Ohio. Stand Energy Corp. and Local Union 1347, International Brotherhood of Electrical Workers, AFL-CIO subsequently signed the stipulation.

(5) Also on May 8, 2000, a stipulation on CG&E's employee assistance plan was filed on behalf of CG&E; the staff; Industrial Energy Users-Ohio; The Ohio Council of Retail Merchants; AK Steel Corporation; Kroger Company; The Ohio Manufacturers' Association; The Ohio Hospital Association; Columbia Energy Services Corp.; Columbia Energy Power Marketing; Exelon Energy; Strategic Energy; Mid-Atlantic Power Supply Assoc.; Ohio Consumers' Council; New Energy Midwest, LLC; WPS Energy Services, Inc.; and Enron Energy Services, Inc. A third stipulation on CG&E's independent transmission plan was filed on May 8, 2000, on behalf of CG&E; the staff; Ohio Consumers' Council; The Ohio Council of Retail Merchants; Industrial Energy Users-Ohio;

Kroger Company; The Ohio Manufacturers' Association; New Energy Midwest, LLC; WPS Energy Services, Inc.; Enron Energy Services, Inc.; Dynegy, Inc.; and The Ohio Hospital Association.

(6) Prehearing conferences were held on April 5, and May 11, 2000. The evidentiary hearings were held on May 30, June 1, 2, 5, 6, 8, and 14, 2000.

(7) A local public hearing was held in Cincinnati, Ohio on June 8, 2000.

(8) Pursuant to Section 4928.39, Revised Code, the total allowable transition costs for CG&E, as agreed to in the transition plan stipulation, are reasonable and include the recovery of $401.4 million of existing regulatory assets and projected $483 million of new regulatory assets, plus certain carrying costs and purchased power costs.

(9) The stipulation provides appropriate shopping incentives to achieve a 20 percent load switching contemplated by Section 4928.40 (A), Revised Code.

(10) CG&E's transition plan, as modified by the stipulations, satisfies the requirements of SB3, and is approved for the reasons and to the extent set forth herein.

It is, therefore,

ORDERED, That CG&E's transition plan and stipulations filed on April 17, 2000, and May 8, 2000, are approved, to the extent set forth in this opinion and order and subject to final approval of CG&E's compliance tariffs. It is, further,

ORDERED, That the tariff amendments and accounting authority requested by CG&E are approved in accordance with the discussion set forth in this opinion and order. It is, further,

ORDERED, That CG&E and other interested intervenors follow the timelines for informal review and comments with respect to the company's compliance tariffs, and that CG&E file an application for approval of its compliance tariffs in accordance with the directives set forth in this opinion and order. It is, further, ORDERED, That a copy of this opinion and order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Craig A. Glazer

Judith A. Jones

Donald L. Mason

SEF/RRG/vrm

Entered in the Journal
AUG 3 1 2000

A True Copy

Gary E. Vigorito
Secretary

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR CERTAIN FINDINGS UNDER 15 U.S.C. § 79Z	)	CASE NO. 2001-058

ORDER

On March 9, 2001, The Union Light, Heat and Power Company ("ULH&P") filed an application setting forth an Offer of Settlement which, if accepted by all parties and the Commission, would freeze retail rates through December 31, 2003, limit rate increases for 3 years thereafter, provide ULH&P with a 5-year wholesale power contract for 2002 through 2006, and resolve a number of rate issues pending in Case Nos. 2000-426 and 2000-517. ULH&P subsequently filed on March 13, 2001 an amended application and Amended Offer of Settlement ("Settlement") which incorporated a number of revisions to its original proposal. ULH&P's application was docketed as Case No. 2001-058 and the Commission, by Order entered March 13, 2001, granted ULH&P's motion to consolidate this case with Case Nos. 2000-426 and 2000-517.

The parties to these consolidated cases include the Attorney General's Office of Rate Intervention, Newport Steel Corporation, and the Kroger Company. A public hearing was held at the Commission's offices on March 20, 2001, and notice of the hearing was published by ULH&P in newspapers throughout its service territory. Each of the parties filed a written statement expressing agreement with and support of the Settlement.

BACKGROUND

ULH&P is a combination gas and electric utility which provides retail electric distribution service to approximately 122,000 customers in parts of the northern Kentucky counties of Boone, Campbell, Grant, Kenton, and Pendleton. ULH&P is a wholly owned subsidiary of Cincinnati Gas & Electric Company ("CG&E") which is, in turn, a wholly owned subsidiary of Cinergy Corp. ("Cinergy"), a registered public utility holding company. CG&E is engaged in the generation, transmission, and distribution of electric energy in and around Cincinnati, Ohio and provides wholesale generation and transmission service to ULH&P. While ULH&P's retail service and rates are subject to the regulatory jurisdiction of this Commission, CG&E's wholesale generation and transmission service to ULH&P is subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC").

ULH&P owns no generating facilities and its transmission facilities are only capable of moving power within its service territory for distribution purposes, as opposed to performing any traditional transmission functions. Under normal operating conditions, ULH&P's transmission system is interconnected only with CG&E. For decades ULH&P has satisfied the electrical requirements of its retail customers by purchasing all of its power and transmission needs from CG&E. These purchases have been made pursuant to a succession of full-requirements contracts which contain a demand and energy charge reflecting a bundled rate for both generation and transmission service. ULH&P's existing full-requirements contract with CG&E has a

10-year term which will expire on January 1, 2002. Although the contract provides that it will automatically continue for successive 1-year terms absent a notice of termination, CG&E gave notice of termination on December 15, 2000. Thus, the existing contract will expire on January 1, 2002, with the ULH&P territory then being without electricity from any source.

For the decades that ULH&P has purchased wholesale power from CG&E, the contract prices have been based on CG&E's embedded cost of generation. This use of cost-of-service-based pricing was for years the touchstone of the rate-making principles followed by FERC. However, in 1996, FERC issued its Order 888 which was designed to promote wholesale competition in the sales of electric energy by requiring utilities to adopt standardized tariffs that offer open-access, nondiscriminatory transmission services.

In furtherance of these efforts to foster wholesale competition in the sale of electric energy, FERC stated as follows:

> We also reaffirm our preliminary determination not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term.
>
> * * *
>
> A requirements customer will be responsible for planning to meet its power needs beyond the end of the contract term by either building its own generation, signing a new power sales contract with its existing supplier, or contracting with new suppliers ....[1]

While FERC's policy to promote wholesale competition may well provide substantial financial savings to wholesale customers purchasing electricity from suppliers whose

[1] FERC Order 888, FERC Stats. & Regs. ¶ 31,036, p. 31,805 (1996).

cost of service is above the available market price, it creates severe financial penalties for those customers who have been purchasing from suppliers whose cost of service is below the market price. This is particularly true here in Kentucky where the cost of electricity is among the lowest in the nation.

The Commission was first informed by CG&E in November 1999 that it was unwilling to continue selling power to ULH&P at cost-of-service rates beyond the January 1, 2002 expiration of the current sales contract. Commission Staff had a number of meetings and discussions with CG&E in an effort to facilitate an extension to the existing cost-of-service contract, but those efforts were unsuccessful. CG&E, the parties to this case, and Commission Staff then commenced negotiations on a new wholesale power contract. After months of intense efforts, the participants agreed in principle to a term sheet, which is embodied in ULH&P's Settlement.

PROPOSED SETTLEMENT TERMS

ULH&P's proposed Settlement covers a broad range of issues, including:

1. A 5-year wholesale power supply at rates that are fixed for the contract term at a level that is $14 million above existing cost of service but less than the current and projected market prices.

2. A freeze of existing retail rates, including a fuel adjustment clause ("FAC") credit of approximately $7.3 million annually, through at least December 31, 2003, with limited rate increases thereafter through December 31, 2006, but only for increases in distribution and retail transmission costs and only if those costs exceed an $8 million floor.

3. Termination of Case No. 2000-426 by ULH&P withdrawing its request to refund and reduce retail rates for 2000 and 2001 to reflect last year's approximately $8 million annual reduction in CG&E's wholesale demand charges to ULH&P for purchased power.

4. Concluding Case No. 2000-517, the Commission's 2-year review of ULH&P's FAC, by finding reasonable and consistent with 807 KAR 5:056 in the context of this Settlement ULH&P's retention of base fuel cost overcollections resulting from a lack of synchronization with last year's reduction in CG&E's wholesale base fuel costs to ULH&P.

5. Entry of necessary findings to enable CG&E to transfer its generating assets to an Exempt Wholesale Generator ("EWG") in accordance with the Public Utility Holding Company Act of 1935 ("PUHCA"), 15 U.S.C. 79Z-5a(c), and for the EWG to continue as wholesale electric supplier to ULH&P, also in accordance with PUHCA.

6. Approval of ULH&P's new tariff, Rider RTP-M, Real Time Pricing-Market Based Rates, for new or expanded loads of 5 MW or more.

COMMISSION ANALYSIS

CG&E owns in excess of 5000 MW of generating capacity located in the Cincinnati/northern Kentucky area. This capacity was constructed for the express purpose of meeting the power needs of retail customers in the combined CG&E/ULH&P service territories of southwestern Ohio/northern Kentucky. All of CG&E's base load capacity is coal-fired, while its peaking units typically operate on natural gas. CG&E is a relatively low-cost energy supplier in the Midwest based on its cost of service to generate electricity. Since FERC has for decades required CG&E's sale of power to

ULH&P to be priced at CG&E's cost of service, ULH&P's ratepayers have also been the beneficiary of relatively low electric rates.

The recent introduction of competition in the wholesale power market seriously jeopardizes ULH&P's low-cost power supply and, unfortunately for northern Kentucky ratepayers, this Commission has no jurisdiction over that issue. Despite the fact that CG&E's generation was planned and built specifically to meet ULH&P's electrical demands, FERC Order 888 extinguishes CG&E's obligation to sell power to ULH&P at cost of service and encourages the power to be sold at a market price. Although CG&E could have extended its existing power contract with ULH&P at a cost-of-service rate, CG&E refused to do so. While market-based pricing may benefit buyers when their suppliers' cost of service exceeds market prices, that situation does not exist for ULH&P and CG&E.

The Commission applauds the successful efforts of the parties and our Staff to negotiate a new 5-year power contract for ULH&P at below-market rates. However, the fact remains that this new contract is priced above cost of service. This would seem to indicate that the most reasonable and least costly way for a utility like ULH&P to secure a long-term power supply at prices not subject to market volatility is to construct and directly own sufficient generating capacity to meet its load. Clearly, the energy crisis in California has made the rest of the nation acutely aware that exorbitant spikes in electric prices and blackouts are the result of utilities failing to own generating capacity or have under fixed price contract adequate generating capacity. While we sympathize with California and its neighboring states whose power supplies are struggling to keep up with demand, we must take all necessary steps to ensure that ULH&P and the other utilities we regulate have sufficient generation at reasonable prices to meet short-term and long-term energy needs.

ULH&P has agreed, as part of its proposed Settlement, to file a stand-alone integrated resource plan by June 30, 2004, and to cooperate in good faith in any earlier Commission-initiated review of ULH&P's wholesale power supply alternatives. The Commission believes that reviewing ULH&P's power supply alternatives will be critical to assuring northern Kentucky that it will have a long-term reliable power supply at the lowest reasonable cost. Due to the multi-year lead time that would be necessary for ULH&P to plan and construct generating capacity, the Commission finds that this review must be done sufficiently before the new wholesale contract expires.

PROPOSED SETTLEMENT

In determining whether the terms of the Settlement are reasonable, the Commission has taken into consideration a number of key elements. The Settlement provides for CG&E, or an EWG affiliate, to supply ULH&P all of its power requirements over the next 5 years at a fixed rate that is approximately 9 percent greater than CG&E's current wholesale cost-of-service rate. Freezing CG&E's wholesale power rate for 5 years transfers the risks of both cost and load increases at the generation and wholesale transmission level from ULH&P to CG&E. Based on recent surges in the costs of natural gas and coal used to generate electricity, and the substantial capital investments that CG&E will be required to make in new environmental controls, CG&E's cost of wholesale power could reasonably be expected to rise significantly over the next 5 years even under cost-of-service-based rates.

Absent the Commission's acceptance of the proposed Settlement, CG&E has stated it will file an application with FERC to adopt a full market price for its power sales to ULH&P. Under that scenario, ULH&P's cost for power would be substantially higher than under the contract now being proposed. CG&E estimates that, based on broker quotes for on- and off-peak blocks of power for the first 12 months of the new contract, the average price for power would be approximately $41.29 per MWH at market-based rates versus $36.60 per MWH under the proposed contract.[2]

Under the terms of the Settlement, the wholesale power costs to ULH&P will be increased by $14 million annually above the power costs incurred during the year 2000. The parties agree that the best way to reflect the increase in wholesale rates to ULH&P is to apply the increase on a revenue basis so the rate design will not be affected. Adopting this proposal will result in the wholesale demand rate increasing from $6,900 per MW to $7,200 per MW, while the energy rate increases from 2.30 cents per KWH to 2.40 cents per KWH. The wholesale transmission rates to be charged by CG&E will be $1.66 per KW plus the ancillary service charges as billed under the FERC-approved ancillary services tariff in effect at the time of filing the application in this case.[3]

Retail Rates

The Commission's primary statutory mandate is to ensure that ULH&P's retail rates are fair, just, and reasonable, and it is with this principle in mind that we review the proposed Settlement. Absent the proposed Settlement, ULH&P's retail rates would decline by approximately $8 million annually to track last year's FERC decrease in

---

[2] Direct Testimony of Leigh J. Pefley at 8.

[3] Application at 8.

CG&E's wholesale demand rate.[4] This decrease would be temporary, lasting only until ULH&P's existing wholesale contract expires on January 1, 2002. Thereafter, ULH&P would be expected to increase its retail rates to recover the higher cost of wholesale power at a market price. In addition, if the proposed Settlement is not adopted, ULH&P would also be able to file at any time an application to increase retail rates to recover any deficiency in earnings. Since ULH&P's retail rates have not been increased since 1992,[5] while its net investment in transmission and distribution ("T&D") has increased over $50 million since that time,[6] it is reasonable to assume that a rate increase could be justified.

As a result of accepting the Settlement, ULH&P's ratepayers will forego immediate rate reduction that would have been adopted in Case No. 2000-426 in return for being insulated from any increase in rates due to (1) wholesale power cost increases through the end of 2006; and (2) T&D cost increases through the end of 2003. Furthermore, while ULH&P may file for a rate increase to become effective in 2004 to recover increases in T&D costs, paragraph 8(c) of the Settlement obligates ULH&P to impute approximately $8 million in annual revenues in any such case for rates to be effective prior to 2007.

Another rate issue to be considered is the impact of the Settlement on FAC revenues. ULH&P's base rates recover significantly more fuel costs than are billed by

---

[4] This decrease was the subject of Case No. 2000-426, which has been incorporated into this case, and would be terminated as a part of the Settlement.

[5] ULH&P's last retail electric base rate increase was in Case No. 91-370 (final Order issued May 15, 1992).

[6] Direct Testimony of Leigh J. Pefley at 15.

CG&E since last year's wholesale rate reduction. ULH&P's failure to properly reflect its true fuel costs in its FAC has resulted in overcollections of approximately $14 million last year and nearly $18 million by the end of this year. To provide ratepayers some credit for these overcollections, ULH&P proposes to utilize a negative FAC factor of .2525 cents per KWH which results in an annual benefit to ratepayers of $7.3 million. This negative FAC factor will become effective upon the date of this Order adopting and approving the proposed Settlement and will continue to be applied every month until the later of December 31, 2003 or the effective date of ULH&P's next general rate adjustment.

Another favorable aspect of the Settlement is that while retail rates are frozen at least through the end of 2003, ULH&P, any party, or the Commission may initiate a case after July 1, 2003 to adjust ULH&P's rates if earnings are deficient or excessive due to changes in T&D costs. In order to determine ULH&P's earnings for rate-making purposes during the 5 years covered by the new power contract, revenues will be based on ULH&P's actual recorded revenues plus $8 million of imputed revenues, pursuant to paragraph 8(c) of the Settlement. This revenue figure will then be reduced by ULH&P's wholesale generation and transmission costs, which are its actual reported power costs adjusted to reflect the transmission rates as agreed to in the Settlement. The provision for imputing revenues, coupled with the FAC reduction that will be ongoing until an adjustment in T&D rates, will give consumers a $15.3 million cushion before T&D rates can be increased over the last 3 years of the power contract. To ensure proper monitoring of ULH&P's earnings under the Settlement, the Commission will require

ULH&P to include certain financial information in its monthly reports to facilitate calculating the adjusted earnings.

EWG Approval

Under Ohio's recently enacted legislation, CG&E is required to fully separate the provision of noncompetitive retail electric service from the provision of all other services. While CG&E could have adopted any number of business structures to comply with this Ohio requirement, it selected a Corporate Separation Plan under which its electric generating assets will be transferred to an EWG.[7] CG&E's Corporate Separation Plan was incorporated into its restructuring Transition Plan, which has been approved by the Public Utilities Commission of Ohio.[8] Under PUHCA, the EWG that acquires CG&E's generating assets is prohibited from selling power to ULH&P unless this Commission enters certain findings of fact to authorize the EWG's power sales to ULH&P. The proposed Settlement will require the Commission to make those requisite findings. The specific findings that must be made pursuant to 15 U.S.C. 79Z-5a(k)(2) are that:[9]

> 1. The Commission has sufficient regulatory authority, resources, and access to books and records of the electric utility company and any relevant associate, affiliate, or subsidiary company to exercise its regulatory duties.
>
> 2. The transaction –
>   a. will benefit consumers,
>   b. does not violate any state law,

---

[7] Amended application at 4.

[8] In Re: Cincinnati Gas & Electric Company, Case Nos. 99-1658-EL-ETP *et seq.*, Public Utilities Commission of Ohio, 2000 Ohio PUC LEXIS 814, August 31, 2000.

[9] Amended application at 5 and 6.

c. would not provide the EWG any unfair competitive advantage by virtue of its affiliation or association with the electric utility company, and

d. is in the public interest.

With regard to the Commission's regulatory authority to access the books and records of Cinergy and its affiliates, ULH&P affirmed its prior commitment, made in 1994 in conjunction with Cinergy's acquisition of ULH&P, to provide the Commission access to the books and records of Cinergy and any affiliate or subsidiary controlled by Cinergy for purposes of verifying transactions with ULH&P.[10] The Commission finds that this access is sufficient to effectively regulate ULH&P after its power requirements are supplied by an affiliated EWG.

The Commission further finds that the sale of power to ULH&P by an affiliated EWG created to own CG&E's generating assets does not violate any Kentucky statute or regulation and that such sale will not create any unfair advantage to the EWG by virtue of its affiliation with ULH&P. The record evidence fully supports the Commission's finding that ULH&P's purchase of power from an affiliated EWG will be in the public interest and will benefit consumers. The transfer of CG&E's generating assets to an EWG and the EWG's assumption of CG&E's obligations under the wholesale power contract with ULH&P will not result in any change to the rights or obligations of ULH&P. The transactions should be seamless to ULH&P. CG&E's generating assets are not now, and never have been, subject to this Commission's rate-making jurisdiction. This Commission has never had the authority to set the price at which CG&E sells power to ULH&P, and this situation will continue after the generating

[10] Transcript of Evidence, March 20, 2001, at 23.

assets are transferred to an EWG. Only FERC has the jurisdiction to set the price for wholesale sales of power by investor-owned utilities. As FERC's policy to have wholesale power sold at market-based prices is achieved, the economic forces of supply and demand will impact ULH&P's wholesale power costs with or without the creation of an EWG for CG&E's generation. It is for this reason that a comprehensive integrated resource plan is critical to ensuring that ULH&P's future power supply will be at the lowest reasonable cost.

ULH&P's Future Generating Sources

Included in the proposed Settlement is ULH&P's commitment to file with the Commission a stand-alone integrated resource plan by June 30, 2004, including a post-contract supply plan. This will allow the Commission and interested parties an opportunity to determine ULH&P's future sources of power supply, including the acquisition of generating assets, prior to the expiration of its new 5-year contract on January 1, 2007. ULH&P further agreed to cooperate in good faith in any review of its power supply alternatives initiated by the Commission prior to June 30, 2004.[11]

Although the negotiations among the parties to this proceeding have culminated in a new 5-year power supply contract priced below the market, the Commission is deeply concerned about the less-than-arm's-length relationship between ULH&P and its affiliated wholesale supplier. It was apparent from the testimony at the hearing that ULH&P's management has embraced deregulating generation, a policy that appears to be in the best interest of CG&E and Cinergy, but not ULH&P's ratepayers. Although this may be inherent in a utility holding company structure, the Commission is

---

[11] Settlement at 10.

committed to assuring that there is no penalty to ULH&P's ratepayers as a result of procuring wholesale power from affiliates. Consequently, the Commission expects ULH&P's next integrated resource plan to include analyses of bids to purchase power from non-affiliated suppliers as well as detailed analyses of constructing generation to lock in prices for the long term. The Commission intends to take all steps necessary to ensure that the northern Kentucky areas served by ULH&P have an assured long-term power supply at the lowest reasonable cost.

Force Majeure

As discussed above, ULH&P owns neither generating assets nor bulk power transmission facilities, and under normal operating conditions is only interconnected with CG&E. Thus, the wholesale power to be purchased by ULH&P must be a firm product with the lowest potential for supplier non-delivery. Under these conditions, the supplier's non-delivery should be excused only in the most exceptional circumstances.

The Commission's review of the *force majeure* definition in the proposed wholesale power sale agreement discloses that the seller may be unnecessarily excused from performance under some circumstances. Particularly troubling is the inclusion in the definition of specific events, such as a fire or a labor dispute, that would seem to automatically trigger a *force majeure*, even when the seller's performance might not otherwise be impossible. To prevent an unnecessary interruption in ULH&P's power supply, the *force majeure* definition in paragraph 1.3 of the Power Sale Agreement should be revised to eliminate the list of specific events that are automatically included. With this change, the contract definition of *force majeure* will more closely conform to the definition adopted by the Edison Electric Institute/National

Energy Marketers Association in their Model Master Power Purchase & Sale Agreement.[12]

Corporate Guaranty

The parties to this case and Staff spent many months negotiating the new 5-year power contract which is an integral part of ULH&P's proposed Settlement. While the primary goal of that process was to obtain a wholesale supply of power for northern Kentucky at the lowest reasonable cost, a secondary goal was to ensure the reliability of that supply. Clearly, a 5-year wholesale power contract will be of little benefit to ULH&P and its ratepayers unless there is some assurance that the seller will be able to deliver on its supply obligations for the full 5-year term.

Due to CG&E's historic ownership of generating assets to serve its native load customers, guaranteeing the supplier's performance was not an issue in the past. Now, however, with the expectation that those assets will be transferred to an EWG and then possibly sold, guaranteeing the seller's performance becomes a critical issue. The Commission takes some comfort in the fact that the proposed wholesale power contract, paragraph 9.2, requires the seller to obtain by January 1, 2002 a corporate guaranty from Cinergy. The Commission finds, however, that the guaranty should be obtained now and included with the executed power sale contract as filed with FERC.

In addition, the Commission has reviewed the draft guaranty, filed in response to a hearing data request, and notes that it includes provisions for future assignment, delegation, or amendment. Since this guaranty is a critical component to assuring the seller's performance, any change to the guaranty may greatly diminish its purpose.

---

[12] 21 Energy Law Journal No. 2 (2000) at 311.

Therefore, we find that the corporate guaranty should be revised to provide that any assignment, delegation, or amendment will be subject to prior Commission approval.

REPORTING REQUIREMENTS

To enable the Commission to properly monitor ULH&P's electric earnings during the Settlement, it will be necessary for ULH&P to file additional financial information with its monthly reports. The information will need to be adequate to allow the Commission or the parties to calculate ULH&P's adjusted electric earnings on its T&D portion of operations. To do so requires excluding the wholesale generation and transmission costs and including the imputed revenues, all as described in paragraph 8 of the Settlement. The Commission will allow ULH&P to design the supplement to its monthly report and submit it with its first monthly report filed 30 days after the date of this Order. If the content of the report is not adequate, the Commission will convene an informal conference among the parties to discuss the deficiencies.

SUMMARY

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds the Settlement as proposed by ULH&P, and agreed to and supported by the parties, is reasonable and should be accepted only if ULH&P agrees to: (1) modify the power sale agreement to eliminate the listing of specific events that constitute a *force majeure*; (2) modify the power sale agreement to require its filing at FERC to be accompanied by the executed corporate guaranty; and (3) modify the corporate guaranty to require Commission approval of any assignment, delegation, amendment, or termination. ULH&P should file a written notice within 10 days of the date of this Order, setting forth its acceptance or rejection of these modifications. The remaining findings herein are conditioned upon ULH&P's written acceptance of the modifications discussed above.

Further, the Commission finds that, in accordance with 15 U.S.C. 79Z-5a(c) and 5a(k)(2), CG&E's proposal to transfer its generating assets to an EWG and the sale of power by that EWG to ULH&P will benefit consumers, does not violate any Kentucky statute or regulation, is in the public interest, and will not provide that EWG any unfair competitive advantage by virtue of its affiliation or association with ULH&P. In addition, the Commission has sufficient regulatory authority, resources, and access to the books and records of ULH&P and the associate, affiliate, and subsidiary companies of Cinergy to exercise its regulatory duties over ULH&P.

IT IS THEREFORE ORDERED that:

1. ULH&P's Settlement, as modified in Finding No. 1 above, is approved and ULH&P shall file a written notice within 10 days of the date of this Order setting forth its acceptance or rejection of those modifications.

2. The provisions of Ordering Paragraph Nos. 3-8 below are conditioned upon ULH&P's filing of a written notice of acceptance of the modifications listed in Finding No. 1 above.

3. ULH&P shall supplement its monthly and annual reports filed with the Commission by filing adequate information to calculate its adjusted earnings after taking into consideration the adjustments described in paragraphs 8 and 9 of the Settlement. The first supplement to ULH&P's monthly report shall be filed with the report submitted for the first full month that ends not less than 30 days after the date of this Order. ULH&P shall continue to file the supplemental information through July 1, 2006.

4. ULH&P's proposed new rate RTP-M is approved for service rendered on and after January 1, 2002. ULH&P shall file revised tariffs incorporating rate RTP-M within no less than 60 days prior to the effective date of the tariff.

5. ULH&P shall file, within 10 days of its notice of acceptance of modifications, a revised FAC tariff to freeze its FAC rate at a credit of .2525 cents per KWH until the later of December 31, 2003 or the effective date of ULH&P's next general retail rate adjustment, pursuant to paragraph 8(b) of the Settlement. The revised FAC tariff shall be effective for bills rendered on and after June 1, 2001.

6. ULH&P's rates shall not be subject to adjustment prior to January 1, 2004 in accordance with paragraphs 8 and 9 of the Settlement.

7. ULH&P's rates shall not be subject to adjustment prior to January 1, 2007 for changes in wholesale generation and transmission costs in accordance with paragraphs 8 and 9 of the Settlement.

8. ULH&P's request to withdraw Case No. 2000-426 is granted and that docket is terminated.

9. The fuel issues under review for the 2-year period of November 1, 1998 through October 31, 2000 in Case No. 2000-517 are resolved by the Settlement, and that case is terminated.

Done at Frankfort, Kentucky, this 11th day of May, 2001.

By the Commission

ATTEST:

Executive Director